Decision **PROPOSED DECISION OF ALJ ROSCOW** (Mailed 5/22/2018)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Approval of its 2016 Rate Design Window Proposals.	Application 16-09-003

DECISION ON SOUTHERN CALIFORNIA EDISON COMPANY'S 2016 RATE DESIGN WINDOW APPLICATION

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DECISION ON SOUTHERN CALIFORNIA EDISON COMPANY'S 2016 RATE DESIGN WINDOW APPLICATION

Summary

This decision addresses the application of Southern California Edison Company (SCE) for approval of its 2016 Rate Design Window proposals to revise its standard time-of-use (TOU) periods and seasons, implement Critical Peak Pricing (CPP) for certain customers, and revise its real-time-pricing (RTP) rate. The Commission makes the following determinations:

- SCE's current definitions of two seasons for its TOU rates are retained: summer (June through September) and winter (October through May);
- New Base TOU periods are established to reflect California's changing energy market:
  - An on-peak period of 4:00 p.m. to 9:00 p.m. for summer weekdays;
  - A mid-peak period of 4:00 p.m. to 9:00 p.m. for summer weekends and for winter weekdays and weekends;
  - A super off-peak period from 8:00 a.m. to 4:00 p.m. for winter weekdays and weekends; and
  - An off-peak period in the summer and winter for all other hours.
- SCE and all affected renewable energy water districts, as defined herein, are directed to work collaboratively in SCE's currently-open General Rate Case Phase 2 proceeding to develop an indifference mechanism that, by mutual agreement, will have the result that SCE's Renewable Energy Self-Service Bill Credit Transfer program continues to be a viable mechanism for the governmental entities that currently participate in the program;
- SCE's proposed changes to its Critical Peak Pricing (CPP) rates are approved;
- SCE's alternative proposal to offer CPP as an optional rather than a default rate to customers on its TOU-GS-1 and TOU-PA-3 rate schedules is denied without prejudice;

- SCE's proposed changes to its Real-Time Pricing tariffs are approved;
- SCE's proposed plan for a Marketing, Education, and Outreach campaign for its new TOU period roll-out is approved; and
- The 400 MW cap on Option R enrollment is left undisturbed.

Any rate or tariff modifications required to implement this decision shall take effect no sooner than February 1, 2019 and shall be implemented concurrently with any rate changes adopted in SCE's pending General Rate Case Phase 2 proceeding.

This proceeding is closed.

1. Procedural History

On September 1, 2016, Southern California Edison Company (SCE) filed Application (A.) 16-09-003, its *Application of Southern California Edison Company for Approval of its 2016 Rate Design Window Proposals* (Application). Pursuant to the Commission's modified Rate Case Plan, SCE and other investor-owned utilities (IOUs) may request rate design changes in years other than those covered by the rate design phase of their General Rate Cases (GRCs), via what is termed a Rate Design Window (RDW) application.[1] This application falls between SCE's most recently-concluded GRC Phase 2 proceeding (Application (A.) 14-06-014, resolved by Decision (D.) 16-03-030) and its most recently filed, still-pending GRC Phase 2 application (A.17-06-030) and is thus timely filed.

SCE filed this application in compliance with a settlement approved by the Commission in D.16-03-030. That settlement, the "Marginal Cost and Revenue

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[1] The referenced IOUs, or Investor-Owned Utilities, are SCE, Pacific Gas and Electric Company (PG&E) and San Diego Gas and Electric Company (SDG&E).

Allocation Settlement Agreement," required SCE to file a RDW application no later than September 1, 2016, to include the following studies and proposals:

- SCE shall investigate and propose (if warranted) new default time-of-use (TOU) periods;
- The new TOU periods shall not result in modifications to the settled-upon revenue allocations approved by D.16-03-030;
- The new TOU periods shall reflect changes to the load curve net of Renewables Portfolio Standard (RPS) generation capacity output (the "net load curve"); and
- SCE will include a new study of the time dependence, and, at its option, the temperature-dependence, of its marginal subtransmission and distribution costs.

SCE originally proposed to implement any changes resulting from this proceeding in October, 2018 but in rebuttal testimony modified its proposal to implement the new TOU periods established in this proceeding for all nonresidential customers on most TOU rate schedules (*i.e.*, rate schedules other than those with a super off-peak rate) no sooner than February, 2019. This later date is intended to coincide with the likely implementation date for any changes from SCE's GRC Phase 2 application.

On October 7, 2016, protests to SCE's application were filed and served by the Commission's Office of Ratepayer Advocates (ORA), California Solar Energy Industries Association (CALSEIA), Solar Energy Industries Association (SEIA), the City of Lancaster (Lancaster), and the California Farm Bureau Federation (Farm Bureau).[2] SCE replied to the protests on October 17, 2016.

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[2] On February 7, 2018 CALSEIA submitted a "Notice of Name Change from California Solar Energy Industries Association to California Solar & Storage Association (CALSSA). In the interest of clarity, this decision maintains references to CALSEIA alone where

Footnote continued on next page

On December 8, 2016, the assigned Administrative Law Judge (ALJ) conducted a prehearing conference in order to determine parties, discuss the scope and schedule of the proceeding, and address other procedural matters. A workshop was held on the same day in order to provide SCE, intervenors, and Commission staff the opportunity to discuss the methodologies supporting SCE's proposed TOU periods.

The assigned Commissioner issued the Scoping Memo and Ruling (Scoping Memo) on March 21, 2017. The Scoping Memo defined the issues that would be considered in the proceeding, established a schedule, confirmed the preliminary categorization of the proceeding as ratesetting, and confirmed the need for evidentiary hearings.

Opening testimony was served on April 28, 2017 by ORA, SEIA, CALSEIA, Agricultural Energy Consumers Association (AECA), Farm Bureau, California Large Energy Consumers Association (CLECA), the California Manufacturers & Technology Association (CMTA), Energy Users Forum (EUF), Castaic Lake Water Agency (CLWA), Rancho California Water District (RCWD), Renewable Energy Water Districts (REWD) and Small Business Utility Advocates (SBUA).

As directed by the Scoping Memo, on April 28, 2017 SCE served supplemental testimony that explained how SCE's application addresses certain elements identified within the Commission's "Distributed Energy Resources Action Plan" (DER Action Plan). This supplemental testimony has been received into evidence as Exhibit SCE-02.

SCE, CLECA and CMTA (jointly), EUF, and CALSEIA served rebuttal testimony on June 9, 2017.

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appropriate, but references "CALSEIA/CALSSA" in those more recent instances when the newly-named entity filed or served documents.

On August 7, 2017 SCE filed and served several stipulations:

- SCE-Agricultural Parties Joint Stipulation Resolving Issues in SCE 2016 RDW Proceeding (Exhibit SCE-CFBF-AECA-1)
- SCE-CLWA Joint Stipulation in SCE 2016 RDW Proceeding (Exhibit SCE-CLWA-1)
- SCE-SBUA Joint Stipulation Resolving Issues in SCE 2016 RDW Proceeding (Exhibit SCE-SBUA-1)

Two days of evidentiary hearings took place on August 7 and 9, 2017.

Pursuant to Rule 12.1(b), on August 17, 2017 SCE provided notice to all other parties of its intent to conduct a settlement conference with respect to the joint stipulation between SCE and SBUA. On August 24, 2017, SCE and SBUA filed a Joint Motion for Adoption of Settlement Agreement regarding that stipulation.

Opening briefs were filed on September 9, 2017 by SCE, ORA, Farm Bureau, SEIA, SBUA, EUF, ORA, CMTA, RCWD, CALSEIA, and CLECA.

Reply briefs were filed on September 29, 2017 by SCE, ORA, SEIA, CMTA, and CLECA, at which time this proceeding was submitted for Commission decision.

2. Issues to be Decided

The Scoping Memo determined that the following issues are within the scope of this proceeding:

1. Whether the Commission should approve SCE's proposal to revise its standard TOU periods and seasons, and implement the revised standard TOU periods for all non-residential customers on rate schedules with standard TOU periods;[3]

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[3] SCE clarifies that rate schedules with "standard" TOU periods are those rate schedules whose TOU periods align with the TOU periods used for marginal cost and revenue allocation studies. SCE further notes that the Commission and other parties at times refer to standard TOU periods as "default" TOU periods. (SCE Application at 6.)

2. Whether the Commission should approve SCE's proposal to implement default critical peak pricing (CPP) for more than 500,000 small and medium commercial customers and 1,500 large agricultural customers, or adopt SCE's alternate proposal, which would make CPP optional for small commercial customers only;
3. Whether the Commission should approve SCE's proposal to revise its real-time-pricing rate;
4. Whether the Commission should eliminate the cap on enrollment on SCE's Option R tariffs; and
5. Examination of how SCE's application addresses any or all of the "vision" and "continuing" elements identified within the Rates and Tariffs group of the DER Action Plan.

3. Time-of-Use Policymaking at the Commission

Some of the comments on the proposed decision (PD) of the ALJ argued that the PD reached determinations on SCE's proposals that were inconsistent with previous Commission directives. In order to assist parties in understanding our decision on SCE's application, we provide here an in-depth review our recent TOU policymaking. First, we review our reasons for recently conducting a Commission rulemaking dedicated to this subject. Second, we review our determinations at the conclusion of that proceeding regarding the path forward that we expected interested parties to follow in what we found to be a significant but necessary revision of then-existing TOU periods.

3.1. Rulemaking 15-12-012

In 2015, the Commission opened Rulemaking (R.) 15-12-012 in order to consider a framework for designing, implementing, and modifying the hourly time periods underlying the TOU rates that are the basis for electricity charges of many customers in California.[4] Setting higher TOU rates during peak periods provides customers an incentive to reduce energy use by signaling that electricity is more costly at certain hours of the day. As such, TOU periods were designed to reflect time variations in a utility's cost to serve loads, with higher-priced periods during summer week-day afternoons when the loads were the highest.

When the Commission opened R.15-12-012, it explained that as more customers are enrolled on TOU rate schedules, it is increasingly important that the time periods and corresponding prices defined in TOU rates provide accurate incentives for energy generation, storage, and use at appropriate times throughout each day. The Commission also stressed the timeliness of the Rulemaking. As the proportion of California's energy generated by renewable resources has increased, solar energy has been offsetting or supplying a larger proportion of demand during the traditional times of peak energy use, weekday afternoons.

The Commission's observations were affirmed by the California Independent System Operator (CAISO), which manages much of California's electric grid to ensure reliability. According to the CAISO, the increase in intermittent, non-dispatchable energy from renewable sources, combined with the availability of electricity from existing baseload generation from fossil sources, was expected to result in the availability of plentiful electricity during early afternoon hours, where historically demand has been higher and more expensive to serve. As a result, "net load" (total electric demand minus the amounts supplied by solar and wind generation) is now predicted to "ramp up" and increase rapidly in evenings, as demand remains high but solar power is no longer available after

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[4] Rulemaking 15-12-012, "Order Instituting Rulemaking to Assess Peak Electricity Usage Patterns and Consider Appropriate Time Periods for Future Time-of-Use Rates and Energy Resource Contract Payments", filed December 17, 2015.

sundown. The hourly price of electricity would follow these trends in demand, with lower prices in the afternoon and higher prices in the evening.[5]

For these reasons, the Commission opened R.15-12-012 to aid its determination of whether peak usage periods or periods during which electricity costs are especially high or especially low may be shifting to later in the day. The Commission noted that properly defined TOU periods will provide incentives for customer use and development of future generation that better reflect the needs of the state's electric grid. This, in turn, should assist in reaching state energy goals by minimizing costs, reducing greenhouse gas emissions (GHG), encouraging conservation, and increasing the supply of electricity at times that best serve the needs of the grid.[6]

3.2. Decision 17-01-006

The TOU rulemaking concluded with the Commission's adoption of D.17-01-006, its "Decision Adopting Policy Guidelines to Assess Time Periods for Future Time-of-Use Rates and Energy Resource Contract Payments." As anticipated in R.15-12-012, the Commission found that an update of TOU periods was warranted because the deployment of grid-connected and behind-the-meter solar has increased the availability of energy during the afternoon and decreased the load on the grid at that time. As a result, the peak periods, in terms of grid needs and cost, have shifted to later in the day.[7] The Commission also noted that the CAISO's participation in R.15-12-012 brought a focus on grid reliability, with a particular concern about times when the available renewable generation is high

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[5] *Id.* at 6.

[6] *Id.* at 2.

[7] D.17-01-006, Finding of Fact 4.

but load is low. Such situations in the past have forced the CAISO to curtail a small percentage of renewable generation.[8]

As the title of D.17-01-006 indicates, the Commission did not adopt specific TOU time intervals or rate design elements for any IOU. Rather, it adopted a framework, including guiding principles, for designing, implementing, and modifying the time intervals reflected in TOU rates, which would take place in future, IOU-specific proceedings. The guiding principles adopted in D.17-01-006 are attached to this decision as Appendix 1, and articulate the framework to guide those future proceedings in order to determine proper TOU time periods and TOU rate design elements. The Commission anticipated that parties in those proceedings would follow the guidelines to determine TOU time periods during which customers, generators, and providers of energy services should be encouraged to modify electric usage and supply. The results would be designated as "Base TOU periods," which the Commission defined as "the periods during which it would be helpful to the California power grid for customers to modify energy use levels."[9]

SCE filed the instant application nearly five months before the Commission adopted D.17-01-006. As will be seen below, in testimony served after the Commission issued that decision, parties frequently invoked its guiding principles to support their positions regarding SCE's proposals in this proceeding, and SCE answered in kind. Thus, even though D.17-01-006 is not binding on this proceeding, we are comfortable referencing its guidance as we consider the TOU periods proposed by parties herein. However, we also note that some of the

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[8] *Id.* at 5-6

[9] D.17-01-006 at 11.

guiding principles were clearly forward-looking in nature, suggesting or requiring utility actions in future proceedings, initiated after January 2016. We will not apply those principles in hindsight to our review of SCE's proposals here.

In a general response to comments on the PD, we also clarify that in D.17-01-006 the Commission envisioned that Base TOU periods would serve as a starting point for designing TOU rates,[10] but articulated a number of qualifications to that hard-and-fast rule that should also be considered in any review of proposed TOU periods.

First, the Commission specified that in addition to Base TOU periods, TOU rate designs must consider customer understanding and ability to respond to TOU price signals.[11] Indeed, even as it acknowledged the CAISO's concerns about grid reliability, the Commission also noted that the CAISO's analysis did not address <u>customer acceptance</u> of TOU changes.[12] In fact, parties in the instant proceeding should take note that the Commission devoted considerable discussion in D.17-01-006 to the importance that it placed on considering customer preferences, understanding, and acceptance of TOU rates:

> We recognize the importance of promoting customer understanding and acceptance as an essential element in the success of TOU rates in motivating customers to shift energy usage. The incentive offered by TOU rates can only work, however, if: 1) the customer understands that his or her rates are time differentiated, and 2) the customer is able to adjust his or her energy use in response to the price signals that time differentiation provides.[13]

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[10] *Ibid.*

[11] *Id.* at 3.

[12] *Id.* at 5-6, emphasis added.

[13] *Id.* at 37.

We emphasize that while the Commission stressed the quantitative primacy of "getting it right" when creating new TOU periods to reflect the realities of today's grid, it continued to stress the qualitative importance of customer acceptance. We have therefore considered the dual guidance provided in D.17-01-006 as we evaluated the TOU period proposals in this proceeding:

> Although the primary input for TOU rates should be the time periods identified through the marginal cost analysis, rate design must take into account customer understanding and acceptance. Any resulting modifications should not stray far from the Base TOU periods and cost of service principles.
>
> After the IOUs establish factual data supporting Base TOU periods, customer preference considerations can be used to refine TOU periods (e.g., number of periods, length of each, price differentials) for translation into rate options and levels. Customer acceptance may be reason to temper cost-based rates, to maintain certain existing TOU features, or to keep TOU periods stable for longer periods of time to allow for adjustment.[14]

The Commission provided similar forward-looking guidance for subsequent rate design proceedings. This task that is not within the scope of this proceeding, but the Base TOU periods adopted here will serve as the starting point in subsequent SCE rate design proceedings. Therefore, we take note of, and direct parties' attention to, the following observations in D.17-01-006:

> Most parties also agree that there is good reason to offer different TOU rates within a customer class. The result is strong support for a menu-based approach giving customers choice as a means of promoting customer acceptance.
>
> These different TOU rates should be cost-based. This does not mean that price differentials must reflect the absolute ratio of costs allocated to the different TOU periods. Rather, price signals should reflect the

[14] *Id.* at 36-37.

> direction of differences in marginal costs by TOU period. This approach will ensure that different TOU rates will not send conflicting price signals, but, to maintain the relationship to costs, we have required that TOU rate designs not stray dramatically from the Base TOU periods. In addition, basing rates on TOU-period-specific marginal cost will ensure that each TOU rate should reflect the costs to serve the customers on that rate (except in case of specific, identified, policy-based or statutorily-required subsidies). Although reflection of cost-causation may be muted when new TOU rates are initially being introduced, over time each rate design should be able to reflect the cost to serve enrolled customers with increasing accuracy.[15]

The Commission made one additional accommodation to customer acceptance of new TOU periods in D.17-01-006, stating that new TOU periods should be introduced in a manner that reduces or mitigates negative impacts on customers, such that transition mitigation measures may be necessary for some customers when transitioning to new TOU periods. The Commission allowed certain existing solar customers to retain their current TOU periods for five years (residential) or ten years (non-residential) and directed that the treatment of transitions for other customer groups and for future TOU periods changes should be addressed in subsequent IOU-specific rate cases by applying the guiding principles adopted in D.17-01-006.

4. Relief Sought, Evidentiary Standards, and the Burden of Proof

As noted above, SCE filed this RDW application nearly five months before the Commission adopted D.17-01-006. However, having actively participated in R.15-12-012, SCE to a large degree anticipated the guidance from that proceeding

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[15] *Id.* at 39-40.

when developing its RDW proposals. We summarize the relief sought by SCE below.

First, SCE seeks Commission approval of its revised Base TOU periods.[16] Tables 1-A and 1-B below summarizes SCE's proposal:

Table 1-A

SCE Current and Proposed TOU Periods (Weekdays)

TOU Period	Summer (June – September)		Winter (October – May)	
	Current	Proposed	Current	Proposed
On-peak	12 p.m. - 6 p.m.	4 p.m. - 9 p.m.		
Mid Peak	8 a.m. - 12 p.m. and 6 p.m. - 11 p.m.		8 a.m. - 9 p.m.	4 p.m. - 9 p.m.
Off-peak	11 p.m. - 8 a.m.	All hours except 4 p.m. - 9 p.m.	9 p.m. - 8 a.m.	9 p.m. - 8 a.m.
Super-off-peak	N/A		N/A	8 a.m. - 4 p.m.

Table 1-B

SCE Current and Proposed TOU Periods (Weekends)

TOU Period	Summer (June – September)		Winter (October – May)	
	Current	Proposed	Current	Proposed
On-peak				
Mid Peak		4 p.m. - 9 p.m.		4 p.m. - 9 p.m.
Off-peak	All hours	All hours except 4 p.m. - 9 p.m.	All hours	9 p.m. - 8 a.m.
Super-off-peak				8 a.m. - 4 p.m.

SCE also seeks Commission approval of the following:

[16] SCE clarifies that rate schedules with "standard" TOU periods are those rate schedules whose TOU periods align with the TOU periods used for marginal cost and revenue allocation studies. SCE further notes that the Commission and other parties at times refer to standard TOU periods as "default" TOU periods. (SCE Application at 6.)

- its proposal to implement default critical peak pricing (CPP) for more than 500,000 small and medium commercial customers and 1,500 large agricultural customers, or adopt SCE's alternate proposal, which would make CPP optional for small commercial customers only;
- its proposal to revise its real-time-pricing rate; and
- its proposed plan for a Marketing, Education, and Outreach campaign for its new TOU period roll-out is approved.

As the applicant, SCE bears the burden of proving that it should be granted the relief sought in its application, and must affirmatively establish the reasonableness of all aspects of its request. This is the Commission's standard for applications submitted pursuant to its Rate Case Plan. However, since some parties strongly opposed some of the determinations reached in the PD, we note that the counterpoint to the applicant's burden is the burden the Commission places on intervenors in proceedings, the burden of producing evidence:

> [W]here other parties propose a result different from that asserted by the utility, they have the burden of going forward to produce evidence, distinct from the ultimate burden of proof. The burden of going forward to produce evidence relates to raising a reasonable doubt as to the utility's position and presenting evidence explaining the counterpoint position. Where this counterpoint causes the Commission to entertain a reasonable double regarding the utility's position, the utility has not met its ultimate burden of proof.[17]

With these foundational principles in mind, we now turn to the substance of this proceeding and the issues identified in the Scoping Memo.

[17] D.87-12-067, 27 CPUC2d 1, 22.

5. Marginal Cost Studies

SCE begins its substantive showing by reviewing marginal cost principles. As noted by SCE, this Commission's reliance on marginal cost principles for revenue allocation and rate design is "long-standing and based on well-founded economic principles."[18] SCE also notes that in D.17-01-006 the Commission found that Base TOU periods should be developed using forward-looking data, with the forecast year set at least three years after the Base TOU periods will go into effect. Accordingly, the TOU pricing periods SCE proposes in this proceeding are based on its updated marginal cost analysis of generation energy and capacity costs, as well as an assessment of the time differentiation of certain distribution system costs. SCE developed its marginal cost studies using forecasts of supply-and-demand conditions expected in 2024, which is approximately five years out from SCE's proposed implementation date for the updated TOU periods, February 2019.

Although the Commission's reliance on marginal cost principles is long-established, parties in this proceeding disagreed on some of the numerical inputs to those calculations. These disagreements must be resolved before we review parties' proposed TOU periods.

5.1. The Appropriate Reference Year

Public Utilities Code Section 745(c)(3) directs the Commission to "strive" for residential TOU periods that are appropriate for at least the following five years. While we are not setting residential TOU periods in this proceeding, SCE states that the cost basis for the adopted non-residential TOU periods will be used to inform SCE's January 1, 2018 RDW application addressing the rate design and implementation of default TOU rates for residential customers. Therefore, SCE

[18] Exhibit SCE-01 at 12.

recommends that forecasts of supply and demand conditions in 2024 serve as the basis for the marginal cost analyses to determine its Base TOU periods, which will be in place from early 2019 through at least 2024. SCE asserts that in order to ensure that price signals remain appropriate over this period, its TOU periods should be set "based on expected conditions in the future and should have sufficient duration to provide stability over reasonable planning periods for SCE and its customers."[19] That said, SCE prepared its marginal cost study using data from 2021 as well as 2024 so that parties could analyze both scenarios.[20]

SCE notes that the concerns about the accuracy of current TOU periods have been caused by the impact on the load profiles of SCE and other utilities due to the statutory increases in California's RPS targets from 20% in 2013 to 33% in 2020; SCE suggests that these impacts will only intensify as California moves to 40% by 2024 and 50% RPS by 2030, and behind-the-meter distributed generation continues to grow. For these reasons, SCE recommends that 2024 is the appropriate reference year because (1) it is the approximate midpoint between the requirements of 33% RPS (in 2020) and 50% RPS (in 2030), and (2) it is five years after the expected 2019 transition of residential customers to default TOU rates.

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[19] *Id.* at 15.

[20] SCE also provided useful visual demonstrations of its analyses and resulting proposals by preparing "heat maps" using a methodology first developed by the Commission's Energy Division in R.15-12-012. In that proceeding, parties relied upon marginal cost studies to develop "Target Time Periods" during which it would be helpful to the California power grid for customers to modify their level of energy use. In order to facilitate comparisons between various proposals, the Energy Division provided templates for marginal cost studies that expressed marginal generation energy costs and marginal generation capacity costs in dollars-per-kilowatt-per-hour ($/kWh) summed for each hour in the year. The aggregated results were displayed visually in a "heat map" that averaged the costs in each hour, in each month. The heat maps included in SCE's testimony in this RDW proceeding display a color scheme that reflects the 90th percentile of the average hourly value (load or cost, respectively) in red, the 50th percentile of the average hourly value in yellow, and the 10th percentile of the average hourly value in green.

CLECA, CMTA and EUF also support use of 2024 forecast data as the reference year, while ORA and SEIA recommend use of 2021 forecast data.

ORA notes that SCE's proposed use of 2024 data was over five years ahead of their initially-proposed implementation date of October 2018. ORA suggests that using a reference year so far into the future could increase the likelihood of forecasting errors in the development of TOU periods, while the forecasting errors associated with a 2021 forecast would likely be smaller.

SEIA also suggests that SCE's use of a 2024 forecast of its marginal costs as the basis for determining TOU periods interjects an unnecessary level of uncertainty into the forecast.[21] SEIA also cites D.17-01-006 and Guiding Principle number 4, which "directed that TOU periods should be developed using forward-looking data forecasted at least three years after the TOU period will go into effect":

> The three-years-in-the-future requirement clearly shows the Commission's intent to have TOU periods best reflect system marginal costs on average during the minimum five-year period during which the TOU periods actually would be in effect.

Parties appear to agree that D.17-01-006 mandates that Base TOU periods should be developed using forward-looking data, with the forecast year set at least three years after the Base TOU periods will go into effect. Since the Base TOU periods adopted in this decision will go into effect in 2019, only forecasts set in 2022 or beyond literally meet this mandate. We are reluctant to rely on the 2021 forecast, as recommended by ORA and SEIA, although we note that they made their recommendations when SCE's expected implementation date of October 2018 fell within the three-year window. Regarding those parties' concerns about

[21] Exhibit SEIA-01 at 8.

reduced accuracy of a later 2024 forecast, we note that SCE stated in its direct testimony that the differences in its marginal cost studies for 2021 and 2024 for the purposes of TOU period determination are not significant.[22] In its rebuttal testimony, SCE provided a more detailed comparison it its 2021 and 2024 cost profiles. SCE prepared "heat map" charts to show graphically that "the hourly cost profiles for years 2021 and 2024 are generally consistent and both align with SCE's proposed TOU periods."[23]

We are reassured by SCE's testimony and demonstration that the differences in the results of its marginal cost studies for 2021 and 2024 with regard to determining TOU periods are not significant. Therefore, SCE's marginal cost study using data from 2024 should be used in the marginal cost analyses for setting SCE's Base TOU periods.

We next turn to parties' proposed marginal generation, distribution and transmission costs.

5.2. Marginal Generation Costs

There are two categories of marginal generation costs that capture the cost of serving an additional increment of customer demand: marginal energy costs and marginal generation capacity costs. First, the Commission's methodology relies on a "system market energy price" for estimating the avoided cost of energy. Second, for the marginal generation capacity cost, the Commission's methodology relies on a proxy for estimating the avoided cost of capacity. SCE argues that this remains an appropriate approach in California's current "hybrid" market, where energy procurement is transacted largely through market transactions, and capacity

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[22] *Ibid.*, footnote 30.

[23] Exhibit SCE-03 at 42-43, including Figure III-23 and III-24 (showing average hourly costs in 2021 and 2024).

requirements are met through a combination of utility long-term procurement and annual resource adequacy (RA) requirements.

5.2.1. Marginal Energy Costs

Marginal energy costs (MECs) reflect the hourly marginal market-clearing price of the California Independent System Operator (CAISO) wholesale power market, and are forecast using production simulation models of market clearing prices. No party contested SCE's results and SCE incorporated its 2024 MECs in its overall cost analysis supporting its proposed TOU periods.

We approve SCE's uncontested 2024 marginal energy costs.

5.2.2. Marginal Generation Capacity Costs

The proper assumption for marginal generation capacity costs (MGCC) is a more controversial matter among parties.

SCE notes that MGCCs have historically reflected the capacity cost of meeting system peak conditions, with the proxy equaling the deferral value of a combustion turbine (CT) generator. However, as intermittent renewable energy resource penetration has expanded throughout California, multiple parties have identified the need to enhance the Commission's RA program, or the system capacity framework, to include physical attributes for "flexible capacity," which is associated with the ramping need created by increased renewables and shrinking demand.

SCE explains that as the electric system evolves and California progresses towards its 50% RPS requirement, the need for flexible capacity will increase and require the utilities to assess the costs directly associated with the procurement of flexible capacity. For this reason, SCE argues that flexible capacity costs should be recognized as a cost driver relevant to TOU period and TOU price determinations, and these costs should be determined by a marginal cost methodology consistent with the framework adopted in the Commission's RA program. Using a methodology that reflects these changes to calculate a CT proxy and using the MECs it also calculated, SCE derived an annual marginal capacity cost of $147.26 per kW-year.[24] SCE's proposal is supported by CLECA and CMTA. ORA states that it does not object to the marginal cost values SCE used to determine marginal cost values in this proceeding.

CLECA explains why it supports what it describes as "SCE's novel approach":

> Given the increasing levels of mandated renewables procurement, with the associated imposition of increasing ramping needs, [SCE's approach] recognizes the growing concern with steep evening ramps, as well as the use of an advanced CT. SCE's efforts to assign some of these marginal generation capacity costs to both the system and flexibility function are a good first step in reflecting the need for flexibility and its extension into the winter months.[25]

SEIA disagree with SCE's approach. SEIA recommends that this proceeding use a MGCC of $86 per kW-year, which is midway between the 2021 going-forward costs of existing capacity ($27.70 per kW-year) and SCE's estimated cost of new CT capacity ($143.94 per kW-year). SEIA states that $86 per kW-year also is consistent with ORA's recommendation of a 40% reduction to SCE's CT-based costs in SCE's last Phase 2 proceeding.

CMTA opposes SEIA's proposal, arguing that, absent a settlement, there are no legal or evidentiary bases for accepting SEIA's recommendation to simply take the midpoint between two values: the Commission can only approve marginal costs that are based on valid and viable legal and evidentiary foundations. CLECA opposes SEIA's proposal for similar reasons.

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[24] *Id.* at 23.

[25] CLECA Opening Brief at 6.

We agree with parties who argue that, absent a settlement, the Commission should adopt a value for marginal generation capacity costs that is calculated using specific inputs, as SCE has done, rather than considering SEIA's approach of picking a midpoint between an SCE value and a PG&E value. Therefore, we adopt SCE's MGCC of $147.26 per kW-year.

5.2.3. Marginal Distribution Costs

Pursuant to the Commission's adopted methodology, SCE typically separates distribution marginal costs into (1) customer-related components and (2) "design demand" components. SCE explains:

> To maintain service reliability and to meet the demand needs of our customers, SCE expands, upgrades, and reinforces all levels of its electric system, including transmission, sub-transmission, and distribution assets. SCE uses peak load data and load growth forecasts to evaluate whether existing distribution facilities will exceed their loading thresholds (also known as a planning load limit) under normal and abnormal conditions, and plans infrastructure projects to mitigate existing and expected constraints.[26]

Based on the above, customer-related costs are designed to collect some "fixed" portion of the utility's distribution costs (*i.e.*, the costs of connecting a new customer to the grid that are not considered to be dependent on the level of demand or usage of the system, plus any marginal costs of providing service to customers). The "design demand" portion of marginal costs are associated with distribution capacity, and are typically considered "peak load-driven" costs.[27]

Pursuant to a term in the Marginal Cost and Revenue Allocation Settlement Agreement adopted in D.16-03-030, SCE agreed to review the

[26] Exhibit SCE-1 at 33-34, footnotes omitted.

[27] *Id.* at 33.

time-differentiation of distribution costs in this proceeding. This review was motivated by the fact that California's policy of promoting customer choice in the adoption of customer-sited renewable energy systems (i.e., DERs) will require the distribution grid to increasingly serve two different functions:

1. a peak capacity function to meet peak customer demand, which is time-dependent (and should be used to inform the hourly allocation of distribution costs); and
2. a grid or network function that enables the bi-directional transfer of energy to and from customers, which is not time- or peak- dependent.

In order to more accurately reflect these changes in the drivers of distribution marginal costs, SCE developed a "Peak Load Risk Factor" (PLRF) methodology that further splits design demand distribution marginal costs according to those two functions. SCE proposes that this methodology be used on an interim basis in this proceeding, with the expectation that SCE will include a more comprehensive evaluation of distribution costs in SCE's 2018 GRC Phase 2 proceeding.[28]

CLECA endorses SCE's approach, noting "SCE forecasts DER penetration on the distribution system in 2024, and compares the result to 2014 hourly circuit load; SCE concludes that by [2024] 'the timing of circuit peak demands will shift to later in the day and that peaking may occur on the distribution circuits and substations later in the day'."[29]

SEIA disagrees that SCE's PLRF methodology yields a reasonable allocation of marginal distribution costs, for four reasons. Two of SEIA's objections are based on hypotheticals, namely that SCE should not assume that future distributed

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[28] *Id.* at 34.

[29] CLECA Opening Brief, citing Exhibit SCE-1 at 41.

generation (DG) will be sited in the same location as existing DG, and SCE did not account for the possibility that increasing loads from other types of distributed energy resources (e.g., on-site storage, electric vehicle charging, and load management technologies) might offset the forecast load reductions from DG resources. SEIA's third objection involves technical interpretations of SCE's PLRF methodology versus SEIA's preference for a "peak capacity allocation factor" (PCAF) methodology which weights hours that exceed the distribution planning trigger threshold by how much they exceed that threshold. Fourth, SEIA criticizes SCE's use of 2024 PLRFs to analyze 2021 marginal costs.

SCE addressed SEIA's criticisms in rebuttal testimony.[30] SCE offers reasonable counterarguments to SEIA's two hypotheticals, and further explains its PLRF methodology to show that SEIA's criticisms were unfounded. SCE also developed new PLRFs for the year 2021 for its rebuttal testimony and showed that they are generally consistent to its 2024 PLRFs.

We find merit in SCE's approach to implementing the settlement agreement adopted in D.16-03-030, and the resulting methodology for determining distribution marginal costs in this proceeding. SCE responses to SEIA show that it reasonably accounted for future DG penetration, and its methodology and results are also supported by ORA, CLECA and CMTA. We are also reluctant to rely on SEIA's approach, which CLECA showed relies on older data. Therefore, we approve SCE's proposed distribution marginal costs.

5.2.4. Marginal Transmission Costs

Another area of controversy in this proceeding involves the proper role of marginal transmission costs in determining SCE's TOU periods. SEIA asserts that

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30 Exhibit SCE-03 at 30-38.

the Commission's guidance in D.17-01-006 included direction that appropriately designed TOU periods must consider the hourly profile of all elements of a utility's marginal costs that vary with customer usage and demand, that is, energy, generation capacity, transmission, and distribution.[31] SEIA argues that SCE's proposed TOU periods are not compliant with this "principal guideline" because they do not consider marginal transmission costs. This contrasts with SEIA's testimony, which includes the marginal cost of the CAISO-level bulk transmission system, which SEIA defines as the transmission facilities that are regulated by the Federal Energy Regulatory Commission (FERC).

SCE responded to SEIA's criticism by agreeing that it did not include time-differentiation of <u>long-run</u> marginal transmission costs when determining SCE's TOU period proposal, as explained in its testimony.[32] Nevertheless, SCE argues that after some erroneous assumptions used by SEIA are corrected, the inclusion of long-run marginal transmission costs in determining TOU periods does not impact SCE's overall TOU period proposal.[33]

CLECA also devotes a considerable portion of its rebuttal testimony to a critique of SEIA's proposed marginal transmission costs. CLECA acknowledges that the Commission directed that time-differentiated transmission costs adopted by the FERC be considered as part of the cost analysis for determining TOU periods. However, CLECA also notes that for SCE, FERC has not approved time-differentiation of transmission costs or rates (instead, FERC uses an "embedded cost methodology based on a 12- monthly coincident peak" for SCE).

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[31] D.17-01-006 at. 27; *see also*, *I*d. at 12.

[32] Exhibit SCE-1 at 43-44. SCE elaborates on this explanation in its rebuttal, Exhibit SCE-03 at 12-28.

[33] Exhibit SCE-03 at 23-26.

As it has throughout this proceeding, CLECA succinctly places this dispute over methodology into a more understandable context. CLECA explains that the transmission system's basic functions can be described as: (1) meeting reliability needs; (2) meeting policy needs (e.g., enabling renewable resources to serve load); and (3) meeting economic needs (relieving congestion). While a line built for one purpose listed above may serve a secondary purpose on the list, determining the relevant proportions "would require a very careful parsing of costs (a very complex undertaking)."[34] More to the point, the determination of marginal costs does not consider "use": it simply reflects an increase in costs associated with an increase in load. CLECA explains that SCE did not propose marginal transmission costs because "the proportion of expected SCE transmission capital expenditures for load growth is fairly minimal when compared to the amount SCE expects to spend to integrate RPS resources."[35]

Based on the above, CLECA faults SEIA's proposal for marginal transmission costs because SEIA failed to do the necessary analysis to separate transmission investment associated with load growth from transmission investment made for other purposes.

We do not find it necessary to incorporate marginal transmission costs into SCE's TOU period calculations at this time. One of the nuances in the guiding principles that we adopted in D.17-01-006 was that "going forward, the IOUs should include information on marginal distribution costs that contribute to peak load costs and time of use information filed or adopted in FERC transmission rate proceedings. Use of marginal distribution and transmission cost information in

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[34] CLECA Opening Brief at 8, citing testimony at hearing by SCE's witness (Reporter's Transcript [RT] at 81).

[35] *Id.* at 9, citing testimony at hearing by SCE's witness (RT at 79).

setting future Base TOU periods will be addressed in individual IOU rate proceedings."[36] In other words, it is premature to insist on incorporating marginal transmission costs in this proceeding, which SCE filed even before D.17-01-006 was adopted. That decision did direct that transmission cost information should be used in future rate proceedings, and we expect that SCE and other interested parties will place that information before us accordingly.

6. Day Type Differentiation (Weekday/Weekend)

SCE proposes to establish summertime TOU periods that would differ between weekdays and weekends. SEIA opposes this differentiation, preferring the simplicity for the customer of having a consistent set of TOU periods on all days of the week. SCE argues that SEIA's proposal is inconsistent with the underlying cost data, because SCE's rebuttal testimony shows that summer weekday and weekend costs vary dramatically.

CLECA does not oppose SCE's proposals, which CLECA describes as "reflective of reality".[37] EUF supports SCE's proposal on the basis of likely customer acceptance because the definitions are simple to understand and easy to remember, which will ease customer planning and behavior changes.

As will be seen below, our adopted TOU periods reflect SCE's proposed differentiation. We agree with SCE that we should be guided by the underlying cost data.

7. Seasonal Definitions

SCE proposes to maintain its existing four-month summer season (June-September), asserting that the underlying cost data supports the

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[36] *D.17-01-006 at 12, Guideline 2*. Emphasis added.

[37] CLECA notes that the CAISO Department of Market Monitoring Report for 2015 shows that many of the largest ramps in the year occur on weekends.

continuation of SCE's four-month summer definition. SCE also notes that continuity will facilitate customer understanding and acceptance.

SEIA proposes a new six-month summer (May-October). SCE responded by demonstrating that the costs for May and October are more similar to the winter months than to the actual summer months, using its own 2024 data, and the 2021 data relied upon by SEIA. SCE also observes, with the concurrence of SEIA, that the underlying cost data is more supportive of a shorter summer, not a longer one.[38] SEIA also bases its calculations on long-range forecasts of "the expected impacts of climate change on California." In response, CMTA and CLECA argued that SEIA's reliance on such non-cost-based data does not support the proper determination of TOU season definitions, while also noting that the Commission recognized that "forecast assumptions underlying TOU time periods may deviate over time as more up-to-date data become available," and has already included off-ramps and a "five-year (or every other GRC)" schedule to reevaluate TOU periods.

We agree that SCE's definition of the summer season must be data-based, and we decline to speculate on how rapidly advancing climate change may cause the months of May and October to appear more summer-like than they do today. We also agree with CMTA and CLECA that D.17-01-006 included mechanisms that will allow us to update the forecasts underlying SCE's TOU periods, should future conditions indicate the need to do so.

In comments on the PD, SEIA asserts that PD errs in its determination that the underlying cost data supports a four month summer season; according to SEIA, "SCE's own cost analysis clearly supports including October in the summer

[38] SCE Opening Brief, citing Exhibit SCE-01, p. 56, Table IV-5; SEIA Reply Brief at 2.

season."[39] SEIA quotes SCE's explanation of the methodology that it used to decide to retain its current four-month summer season, and then asserts "using SCE's approach of identifying patterns and trends in the highest and lowest costs hours to identify other hours and months that display similar cost characteristics results in categorizing October as a summer month."[40] SEIA elaborates with the following claims:

- Review of SCE's chronological forecast of overall hourly marginal costs shows that there are two prominent spikes in marginal costs, the latter of which occurs very late in September.[41]
- SCE agreed that, with minor variations to the analysis it performed to map these costs to the days of the year, that this price spike would have been mapped to October;[42] SEIA explains its claim in its footnote number 24:

  > The element of SCE's overall hourly marginal costs that cause these spikes in costs are the marginal generation capacity costs which are allocated based on loss of load expectations (LOLEs). See Tr. Vol.1 (SCE-Kahn) p. 44, lines 10-15.
  >
  > The record indicates that there could be some variation in the LOLE results if you vary factors such as hydro conditions, forced outages and maintenance schedules as part of the stochastic analysis performed to determine the LOLEs -- something which SCE did not do. See *Id*., p. 62, line 19 to p.65, line 1.

- Moreover, SCE's marginal cost forecast for 2024 shows that the hourly average weekday prices in the months of June

[39] SEIA Comments on PD at 6-7.

[40] *Id.* at 9.

[41] *Ibid.* SEIA cites RT at 73 (SCE-Pulgar), lines 1-4 "(the prominent spikes in hourly marginal costs occurred on September 25 at 7:00 p.m. and 8:00 p.m.)".

[42] *Ibid.*

> and October are comparable, with the hourly average prices during certain periods of the day being higher in October than June.[43]

Based on this material, SEIA concludes that the "patterns and trends" of higher cost incurrence should have resulted in October being grouped with the summer months of June through September.[44]

Finally, SEIA also asserts that in order to avoid some of the consequences of climate change, "it will be imperative that customers receive the correct price signals which will drive them to reduce consumption during periods of increasingly high demand - such as the month of October. This has been recognized in SDG&E's service territory with the Commission adopting a new summer season for SDG&E which includes October."[45]

SEIA's arguments and recommendations were addressed in reply comments by SCE and CLECA.

SCE asserts that its testimony and briefs already addressed many of SEIA's arguments, and were thus reflected in the PD's adoption of SCE's proposed summer period. We review SCE's testimony and pleadings here, again in order to clarify for parties our reasons for supporting the PD.

First, SCE explains in its opening brief why it disagrees with SEIA's interpretation of the cost data: "SCE demonstrated that the costs for May and October are more similar to the winter months than to the actual summer months,

[43] *Id.* at 10. SEIA cites Exhibit SEIA-100, Question and Answer 3, which is an SCE response to a SEIA data request. In that response, SCE confirmed that SEIA had correctly charted SCE's marginal cost forecast for 2024, showing only the weekday hourly average prices in June and October.

[44] *Ibid.*

[45] *Id.* at 10-11. SEIA cites D.17-08-030 at 17; this is the Commission's decision on SDG&E's GRC Phase 2 proceeding, Application of San Diego Gas & Electric Company for Authority to Update Marginal Costs, Cost Allocation and Electric Rate Design (A.15-04-012).

using both its own data and SEIA's data."[46] SCE first cites to its rebuttal testimony, where it explains

> SCE defines the summer season to include the months of June through September on the basis of an analysis of marginal costs, which shows that the highest costs are distributed mainly in the months of June through September in SCE's proposed peak period (see Table III-5 and Figure III-13).[47]
>
> The costs for May and October are more similar to those of the other winter months, which is why SCE appropriately included these months in the winter season instead of the summer season. In fact, May is a less expensive month on both weekdays and weekends than November, December, January, February, and March.[48]

[46] SCE Opening Brief at 14.

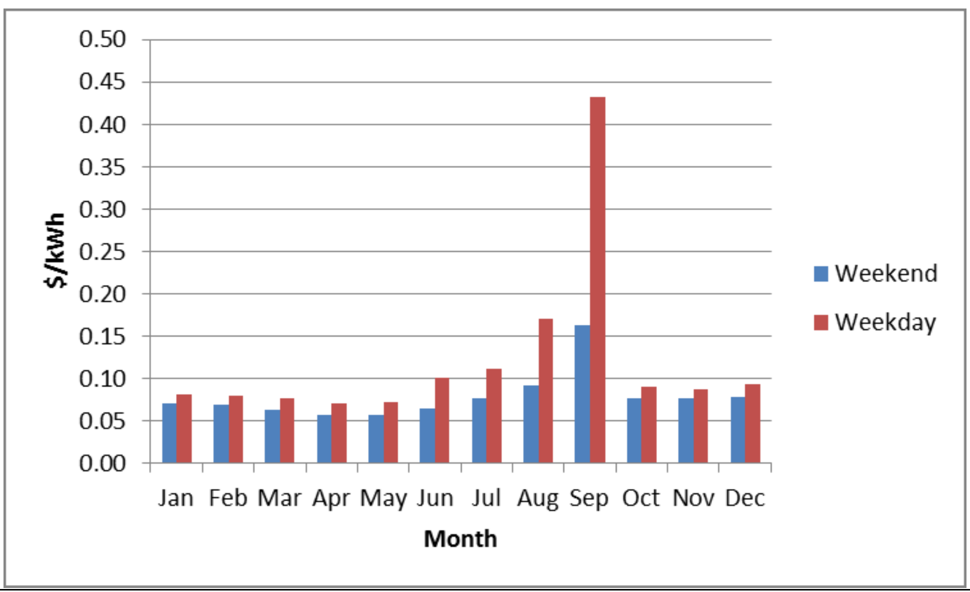
[47] Exhibit SCE-03 at 27. The term "HE" is an abbreviation for "Hour Ending".

[48] *Id.* at 28.

Table III-5
Average Marginal Costs for HE17 – HE21 ($/kWh)

Average Marginal Cost for HE17-HE21($/kWh)		
	Day Type	
Month	**Weekend**	**Weekday**
January	0.0703	0.0811
February	0.0688	0.0798
March	0.0634	0.0768
April	0.0567	0.0707
May	0.0568	0.0723
June	0.0641	0.1003
July	0.0770	0.1107
August	0.0921	0.1709
September	0.1628	0.4319
October	0.0760	0.0899
November	0.0759	0.0877
December	0.0788	0.0928

Figure III-13
Average Marginal Costs for HE17 – HE21 ($/kWh)



For its analysis of SEIA's data, SCE cites to Exhibit SCE-100, which is a chart that SCE prepared using data from SEIA, based on a 2021 (rather than 2024) forecast. That chart shows that even in 2021, average weekday hourly costs for HE14 - HE21 are markedly higher from June through September, whereas May and October hourly costs are essentially indistinguishable from costs from November through March.

SCE concludes:

> It is hard to conceive how May could be considered a "summer" month when considering cost-based criteria, other than its circumstantial placement on the calendar adjacent to June.
>
> Moreover, as SEIA's own data demonstrates, May and October cost data combined is actually less expensive than November and March cost data combined, and the May/October cost profile is starkly different than SCE's current–and proposed–summer months of June-September.[49]

Finally, SCE observes that "If anything, the underlying cost data supports a *shorter* summer, not a longer one" and cites to the table below from Exhibit SCE-01:[50]

[49] SCE Opening Brief at 14.

[50] *Ibid.*, emphasis in the original, citing Exhibit SCE-01 at 56, Table IV-5.

Table IV-5
Distribution of Average Hourly Marginal Costs for Top 20 and Top 100 Forecast 2024 Hours ($/kWh)

	Hour Ending (PPT)					
Month	**16**	**17**	**18**	**19**	**20**	**21**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 1.37	$ 1.37
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 1.63	[redacted]
[redacted]	[redacted]	$ 1.06	$ 2.49	$ 6.91	$ 4.26	$ 2.26
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 1.08	$ 1.08
[redacted]	[redacted]	[redacted]	$ 0.38	$ 0.46	$ 0.39	$ 0.33
[redacted]	$ 0.41	$ 0.43	$ 0.38	$ 0.38	$ 0.86	$ 0.47
[redacted]	$ 0.32	$ 0.59	$ 0.60	$ 2.38	$ 1.76	$ 1.34
[redacted]	[redacted]	[redacted]	[redacted]	$ 0.30	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	$ 0.32	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	$ 0.30	[redacted]	[redacted]	[redacted]

CLECA also asserts that SEIA's claims about high October prices are incorrect. According to CLECA, SCE's marginal energy cost data did not support SEIA's proposal to include October in the summer season. CLECA cites to the following charts from Exhibit SCE-01 (Figure IV-21 and Table IV-4), as well as Table IV-5, already copied above. Examined together, these three charts do appear to indicate that most of the higher-priced hours fall within the months of August and September, and very few in October.

Figure IV-21
2024 Chronological Forecast Overall Hourly Marginal Costs

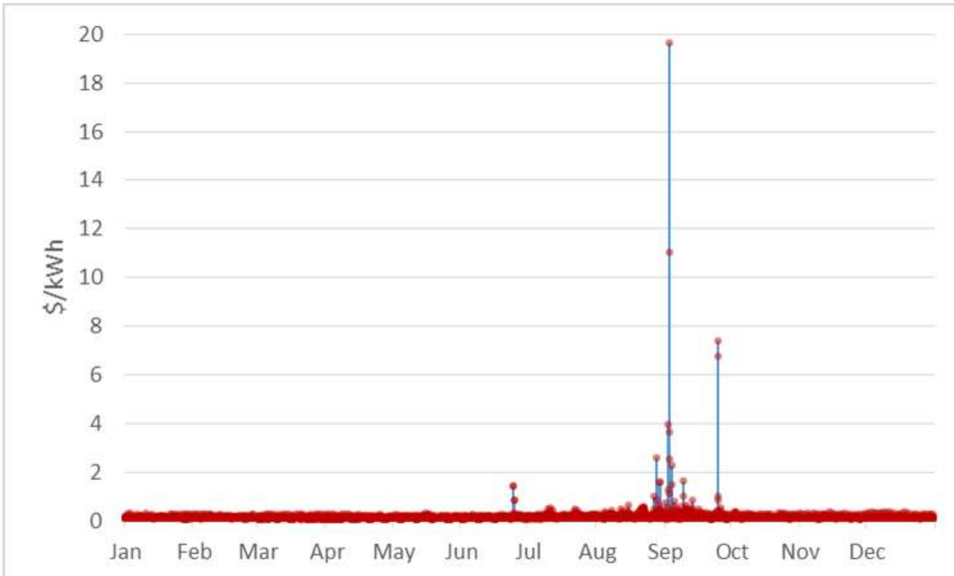


Table IV-4
Frequency Distribution of Highest-Cost 100 Hours by Month (Forecast 2024)

	Hour Ending (PPT)						
Month	16	17	18	19	20	21	Total
June	0%	0%	0%	0%	2%	2%	0%
July	0%	0%	3%	1%	2%	1%	7%
August	1%	2%	7%	7%	11%	5%	33%
September	1%	3%	10%	17%	14%	4%	49%
October	0%	0%	0%	2%	0%	0%	2%
November	0%	0%	1%	0%	0%	0%	1%
December	0%	0%	4%	0%	0%	0%	4%
Total	2%	5%	25%	27%	29%	12%	100%

Finally, CLECA provides its own chart from its written testimony. That chart "incorporated a chart from SCE's testimony, which shows that the weekday hourly costs in the four summer months are much higher and for more hours of the day than for the remaining months, even the months of May and October."[51]

	WEEKDAY (PREVAILING TIME)											
Average of Total Marginal Cost												
Row Lab	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**H1-H24**
1	0.044	0.045	0.047	0.057	0.099	0.169	0.115	0.086	0.074	0.067	0.063	0.056	0.065
2	0.046	0.047	0.047	0.051	0.084	0.162	0.133	0.086	0.072	0.067	0.061	0.055	0.064
3	0.029	0.033	0.041	0.044	0.065	0.131	0.155	0.103	0.078	0.070	0.062	0.053	0.059
4	0.030	0.031	0.039	0.041	0.046	0.102	0.170	0.087	0.080	0.067	0.059	0.052	0.055
5	0.039	0.040	0.043	0.045	0.050	0.106	0.156	0.088	0.087	0.073	0.062	0.054	0.058
6	0.043	0.047	0.051	0.059	0.066	0.112	0.157	0.215	0.194	0.097	0.074	0.059	0.072
7	0.058	0.068	0.077	0.086	0.102	0.203	0.218	0.145	0.134	0.103	0.084	0.068	0.082
8	0.059	0.070	0.080	0.104	0.146	0.235	0.249	0.511	0.248	0.101	0.084	0.070	0.108
9	0.058	0.064	0.076	0.104	0.185	0.381	1.844	1.225	0.374	0.099	0.079	0.066	0.216
10	0.046	0.049	0.052	0.061	0.089	0.180	0.173	0.111	0.084	0.071	0.064	0.056	0.068
11	0.047	0.048	0.051	0.079	0.157	0.200	0.099	0.082	0.072	0.065	0.061	0.056	0.067
12	0.049	0.049	0.051	0.054	0.122	0.255	0.107	0.092	0.080	0.072	0.067	0.058	0.070
Grand T	**0.046**	**0.049**	**0.055**	**0.065**	**0.100**	**0.186**	**0.292**	**0.233**	**0.131**	**0.079**	**0.068**	**0.059**	**0.082**

Regarding the information shown in this chart, CLECA asserts that the costs on both a <u>monthly average</u> and <u>peak price</u> basis demonstrate that the costs for October are much closer to those for November and December than they are for costs for June through September.

First, examining the monthly average prices, CLECA concludes that on a monthly average cost basis October has been properly classified as a winter month:

- the average monthly price for October is $0.068/kWh, which is lower than June's average of $0.072/kWh;
- October's value is very similar to November's $0.067/kWh and December's $0.070/kWh.

Second, examining the hourly peak costs in excess of the 90th percentile, which are marked in red on the chart, CLECA concludes that on a peak price basis, October is properly classified as a winter month:

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[51] CLECA Reply Comments on the Proposed Decision at 2-3.

- while June and October both have 3 hours in the 90th percentile, the peak prices are very different:
    - The highest price in October is $0.180/kWh (hour 18) while the highest price in June is $0.215/kWh (hour 20).
    - October's peak price is closer to the peak price for November of $0.200/kWh (hour 18).
    - December does have an unusual high price in hour 18, but that single hour would not justify classifying December as a summer month.

Finally, both SCE and CLECA dispute SEIA's climate-related support for including October in the summer season ("it will be imperative that customers receive the correct price signals which will drive them to reduce consumption during periods of increasingly high demand"). SCE succinctly observes that "when determining TOU periods, it is costs that matter, not climate"[52] and provides a more technical rebuttal to SEIA in Exhibit SCE-03:

> As stated in the publication *Electric Power Distribution Reliability*, "[m]aximum temperature is only one of the four weather factors that significantly impact electric load. The other three are humidity, solar illumination, and the number of consecutive extreme days…[c]onsecutive extreme days further increases loads since (1) the thermal inertia of buildings will cause them to slowly increase in temperature over several days, and (2) many people will not utilize air conditioning until it has been uncomfortably hot for several days."
>
> In other words, an isolated, anomalous hot day in May does not significantly drive electric load compared to an extended heat storm in late July...
>
> …The factors mentioned above help explain why the first day in May that reaches 95 degrees does not create as much demand for electricity

52 SCE Reply Brief at 2.

used for cooling compared to the third day of a heat storm in July where the maximum temperature also reaches 95 degrees.[53]

Similarly, CLECA asserts that "SEIA missed the Commission's clear direction in D.17-01-006 that TOU periods were to be determined on the basis of costs, not loads."[54]

7.1.1. Discussion of Seasonal Definitions

Based on our review of the record and the comments and reply comments on the PD filed and served by SEIA, SCE and CLECA we see no reason to change the determination made in the PD that October should remain part of the winter season in SCE's territory. SEIA's assertion that "SCE's own cost analysis clearly supports including October in the summer season" is not supported by the evidentiary record. SEIA has not met its "burden of going forward to produce evidence … raising a reasonable doubt as to the utility's position and presenting evidence explaining the counterpoint position."[55]

First, SEIA fails to explain how the fact that a "prominent spike" in marginal costs that occurs "very late" in <u>September</u> lends any support whatsoever to the notion that <u>October</u> should be a summer month. A spike in September is just that, and most neutral observers would not characterize September 25th as "very late" in the month.

Second, CLECA demonstrated in its reply comments that SEIA incorrectly claims that "SCE agreed that, with minor variations to the analysis it performed to

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[53] Exhibit SCE-03 at 28-29, citing Brown, Richard E., *Electric Power Distribution Reliability*, Second Edition (2009), CRC Press at 147.

[54] CLECA Reply Comments at 2, citing D.17-01-006 at 7 and 26. For a longer but well-articulated critique of SEIA's analysis regarding the question of the correct season for October, see the sworn testimony of CLECA witnesses Barkovich and Yap at hearing, RT 197-199.

[55] D.87-12-067, 27 CPUC2d 1, 22.

map these costs to the days of the year, that this price spike would have been mapped to October." The fact remains that SCE's analysis, provided in its sworn testimony, places the price spike in question in September, not October. SEIA also weakens its argument when it demonstrably misrepresents an opposing witness's testimony.

Third, SEIA suggestion that "the record indicates that there could be some variation in the loss of load expectations (LOLE) results if you vary factors such as hydro conditions, forced outages and maintenance schedules as part of the stochastic analysis performed to determine the LOLEs" (emphasis added) is pure speculation, and SEIA itself provided no testimony or exhibits to support this suggestion.

Finally, while SEIA correctly observes that SCE's marginal cost forecast for 2024 shows that the hourly average prices during certain periods of the day are higher in October than June, as shown above CLECA demonstrated in its reply comments that the hourly costs in excess of the 90th percentile support leaving October in SCE's winter season.

8. Proposed Time-of-Use Periods

Based on the marginal cost recommendations discussed above, three parties presented fully developed TOU periods in this proceeding: SCE, ORA, and SEIA. The remaining parties submitted testimony and briefs in support of one of these three proposals. Parties' proposed TOU periods are summarized in the tables below.

Table 2-A
Proposed TOU Periods (Weekdays)

TOU Period	Summer (June – September)			Winter (October – May)		
	SCE	ORA	SEIA	SCE	ORA	SEIA
On-peak	4 p.m. - 9 p.m.	3 p.m. - 8 p.m.	2 p.m. - 8 p.m.			
Mid Peak			noon - 2 p.m.; 8 p.m. - 10 p.m.	4 p.m. - 9 p.m.	3 p.m. - 8 p.m.	2 p.m. - 8 p.m.
Off-peak	All other hours	All other hours	All other hours	9 p.m.- 8 a.m.	8 p.m. - 8 a.m.	All other hours
Super-off-peak				8 a.m. - 4 p.m.	8 a.m. – 3 p.m.	

Table 2-B
Proposed TOU Periods (Weekends)

TOU Period	Summer (June – September)			Winter (October – May)		
	SCE	ORA	SEIA	SCE	ORA	SEIA
On-peak			2 p.m. - 8 p.m.			
Mid Peak	4 p.m. - 9 p.m.	3 p.m. - 8 p.m.	noon - 2 p.m.; 8 p.m. - 10 p.m.	4 p.m. - 9 p.m.	3 p.m. - 8 p.m.	2 p.m. - 8 p.m.
Off-peak	All other hours	All other hours	All other hours	9 p.m. - 8 a.m.	8 p.m. - 8 a.m.	All other hours
Super-off-peak				8 a.m. - 4 p.m.	8 a.m. – 3 p.m.	

8.1. On-peak Period

SCE proposes to shift its on-peak TOU period from noon to 6 p.m. (currently) to 4 p.m. to 9 p.m. (proposed) and states that its proposal is based on marginal costs, as mandated by the D.17-01-006; is consistent with recent CAISO guidance for peak period hours; and that these hours are identical to the on-peak period adopted for SDG&E in D.17-08-030.

ORA states that its marginal cost data, including its flexible ramping capacity allocation method and regression analysis validation, supports an on-peak period of 3 p.m. to 8 p.m. ORA notes that its proposal is a more gradual change from the current on-peak period than SCE's proposal of 4 p.m. to 9 p.m.

ORA also asserts that its proposal more appropriately reflects the policy objectives articulated in R.15-12-012 because it is also based on SCE-specific marginal costs, while taking into account customer considerations more so than SCE's proposal. Finally, ORA notes that its peak-period proposal provides a more gradual change for customers who have faced the same TOU periods for more than 30 years.

SEIA argues that SCE's proposed summer on-peak period of 4:00 p.m. to 9:00 p.m. is not supported by the policies adopted by the Commission in D.17-01-006 and therefore must be rejected. Instead, the Commission should adopt what SEIA describes as its more moderate, cost-based change to a summer peak period of 2:00 p.m. to 8:00 p.m. SEIA argues that SCE's proposed TOU periods are not compliant with a principal guideline in D.17-01-006 because they do not consider marginal transmission costs, while SEIA's proposed summer peak period of 2:00 p.m. to 8:00 p.m. (as well as a two hour "partial peak" period on both sides of the peak period) accounts for all four components of utility service: energy, generation capacity, distribution, and transmission. SEIA also asserts that its proposed on-peak period includes all of the hours with the steepest up-ramps in net loads, and weights each of these hours equally. For these reasons, SEIA asserts that its proposed TOU periods better reflect system cost causation; will provide the most accurate price signals to customers; and will motivate shifts in usage which are the most beneficial to the system.

In its rebuttal testimony SCE faults the ORA and SEIA on-peak period proposals because they both include relatively low-price hours (2 to 4 p.m. and 3 to 4 p.m., respectively), and they both exclude a relatively high-price hour (8 to 9 p.m.). SCE demonstrates in its rebuttal testimony that for 2024 summer weekdays the 3 to 4 p.m. hour is only 77 percent as expensive as the average weekday hour, while the 2 to 3 p.m. hour is even lower-cost (68 percent as expensive). Using the same comparison, the 8 to 9 p.m. hour is 288 percent as expensive as the average weekday hour.[56] For these reasons, SCE believes it has demonstrated that 4 p.m. to 9 p.m. is the correct peak period for SCE's system.

SCE also faults SEIA and ORA because they support their more moderate proposals by using 2021 data, not 2024 data. SCE emphasizes that the stability of TOU periods over a sufficient length of time is important because TOU periods form the basis by which customers make long-term investment choices, without being subject to "constantly-changing and confusing price signals": "in a constantly evolving environment, a moderate shift only increases the likelihood for another change in the near future, which may, in turn, have a detrimental impact on customers' investment decisions."[57] SCE asserts that the more appropriate way to moderate the impact of new Base TOU periods—once they are established—is through rate design implementation in SCE's 2018 GRC
Phase 2 proceeding.

CLECA supports SCE's proposed TOU periods, as "they reflect SCE-specific marginal costs. They also reflect a reasonable effort to create a result that will be straightforward and fairly simple for customers to remember, [by] lining up TOU periods in both summer and winter."[58] As such, CLECA believes they also are understandable and should enable customers to respond by shifting their loads.

CMTA supports SCE's proposed TOU periods because they are cost-based, statistically supportable and based on sound judgment. In particular, CMTA agrees with SCE's recommendation that there be no more than three TOU periods in a season and that a 4 p.m. to 9 p.m. summer peak and 4 p.m. to 9 p.m. winter

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[56] Exhibit SCE-03 at 5, Table II-1.

[57] *Id.* at 9-10.

[58] CLECA Opening Brief at 11, citing Exhibit SCE-01 at 69-73.

mid-peak period be adopted for all months of the year. CMTA agrees with SCE that the hour of 3 p.m. to 4 p.m. should not be included in the peak period "[b]ecause this hour 'typically represents the beginning of the ramp' in the afternoon [and] SCE concluded that including it in the period from 9 a.m. to 3 p.m. would provide a price-signal to encourage usage, which would help increase load and flatten the start of the ramp."[59]

Regarding SEIA's proposed TOU periods, CMTA responds "there should be no debate that for grid operations and reliability purposes, sending the correct price signals in order to flatten the duck curve is imperative. For this reason, SEIA's proposal to start the peak period at 2 p.m. should be rejected, since SEIA's proposal would inaccurately signal customers to reduce loads during the start of the ramp period, thereby exacerbating rather than reducing the continually growing duck curve problem."[60]

8.2. Super-Off-Peak Period

SCE proposes a super off-peak (SOP) period from 8:00 a.m. to 4:00 p.m. for winter weekdays and weekends (October through May).

The PD adopted SCE's proposed super off-peak period. SEIA opposes this outcome in its comments on the PD; the issue was further addressed in reply comments by SCE, CLECA and SEIA. As explained in detail below, we have reviewed the evidentiary record and parties' pleadings on both sides of this issue and we see no reason to change the determination made in the PD that SCE's proposal should be adopted.

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[59] Exhibit CLECA/CMTA-01, Q&A 25, citing Exhibit SCE-01 at 64.

[60] CMTA Opening Brief at 4.

We address parties' concerns as follows. First, as SEIA correctly notes, the PD includes no discussion explaining why the PD adopted SCE's proposal. Therefore, we first discuss the testimony and briefs regarding SCE's proposal, in order to establish what we find to be the objective basis in the proceeding's evidentiary record for adoption of SCE's proposal in the PD. Second, we follow this discussion by addressing parties' comments on the PD and explaining why we leave the outcome reached by the PD unchanged.

8.2.1. Testimony and Briefs

SCE's proposal for a super off-peak period can only be understood and evaluated as the result of the overall methodology followed by SCE to develop its proposed TOU periods. We review the steps followed by SCE here.

SCE begins by noting that its current TOU periods are no longer appropriate in light of its forecast of 2024 marginal costs (the use of which we adopted earlier in this decision). Indeed, no party in this proceeding disputes this basic fact, though they differ on the appropriate reference year.[61]

Next, SCE lists the "guiding principles" that underlie its methodology and its proposal; these principles essentially reflect the Commission's own principles as adopted in D.17-01-006:

1. Utility-specific marginal costs, as defined in Chapter III of Exhibit SCE-01, should be the principal basis for the proposed TOU periods;
2. While the primary goal of correctly-defined TOU periods is to send accurate price signals that address the challenging system conditions identified by the CAISO in its TOU Analysis,[62] the final determination of TOU periods should also consider the principles of customer

[61] *See* Exhibit SCE-01, Figure IV-20 for a graphical representation of the mismatch between SCE's current TOU periods and its forecast 2024 hourly costs.

[62] CAISO TOU Report and Analysis (CAISO TOU Analysis), dated and filed in R.15-12-012 on January 22, 2016, Appendix D.

understanding, acceptance, and ability to respond to the price signals incorporated in the new TOU periods. Such considerations include limiting the number of TOU periods, helping to ensure that TOU periods are not too short, and aligning the starting and ending times for TOU periods across seasons;

3. Stability: TOU periods and associated pricing should be predictable and stable over time to minimize unexpected changes to customers' investments and behaviors.

With these principles in mind, SCE then employed a "grouping" or "clustering" methodology to develop its proposed TOU periods: SCE started with total 2024 marginal costs for each hour and grouped them on an interim basis "to establish the core months and hours that should form the basis of the proposed seasons and TOU periods."[63] SCE states that an overarching goal for defining seasons and TOU periods is to group together hours with similar costs and, at the same time, obtain reasonable separation in costs between TOU periods. The remainder of this section of SCE's testimony details "the considerations that guide the logic to a final design of the TOU periods and seasons." Importantly, SCE stresses that "because many of these considerations are not easily quantifiable, the weight assigned to them reflects a degree of informed judgment and common sense."

As we explain below, we have re-traced SCE's analysis, logic and decision-making through to the end of its process and the resulting proposed TOU periods and we are in agreement with SCE's approach and with the determinations SCE made at each step along the way. This clarification regarding our approach to out

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[63] Exhibit SCE-01 at 50-51. SCE explains that the total marginal cost in each hour of year 2024 is the sum of generation (energy and capacity including flex capacity) and peak-capacity driven distribution system costs.

determinations should be of some assistance to parties who question the basis for our decision to adopt SCE's proposals in this proceeding.

The first finding of SCE's analysis is the fact that "a very limited number of hours, primarily certain hours in August and September, have costs that far exceed the costs for all other hours."[64] From this, SCE concludes that

> The relatively limited number of hours with the highest costs are very distinct from the vast majority of hours with mid-range costs and from the relatively limited number of hours with the very lowest costs. TOU periods and seasons should be established that accurately and separately capture the core hours containing the highest- and lowest-cost hours, as well as the majority of hours in the mid-range cost group.[65]

SCE then expanded its analysis to identify "the core hours and seasons that reflect the highest-costs, lowest-costs, and mid-range costs" and used patterns and trends in the highest- and lowest-cost hours to identify other hours and months that predominantly display similar cost characteristics. Finally, SCE classified the remaining hours that were not clearly associated with other groupings, based on cost characteristics and other considerations, such as overall desire to reasonably simplify or limit the number of seasons and TOU periods, in line with SCE's preference of two seasons and no more than three TOU periods in either season.[66]

SCE displays the results of this process in a heat map that differentiates groups of hours by cost, time and by month. The graphic below is a copy of Figure IV-33 from Exhibit SCE-01, and shows SCE's proposed TOU periods overlaid on average hourly marginal costs for weekdays and weekends. The colored boundary lines mean the following:

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[64] *Id.* at 51-52, including Figure IV-21.

[65] *Ibid.*

[66] *Id.* at 53-54.

- the red boundary includes the summer on-peak period
- the yellow boundary includes the summer and winter mid-peak periods
- the dark green boundary includes the winter super off-peak period
- the light green boundary includes the summer and winter off-peak periods

Figure IV-33
Overlay of Proposed TOU Periods on Average Hourly Marginal Cost Heat Maps

SCE provides a refreshingly candid review of its analysis, in essence critiquing its own results. We quote and annotate much of that section below (adding headings for clarity, as well as bolded emphasis) because we find that SCE has properly considered and weighed the tradeoffs inherent in such exercises, and found the proper balance between "accuracy, simplicity, and customer preference":[67]

> <u>Does the data support establishing a third season?</u>
>
> [This] analysis of costs could theoretically support the addition of a spring season, and it is reasonable to consider whether a third season from March through May with a super off-peak period from 8:00 a.m. to 4:00 p.m. should also be established.
>
> Adoption of three seasons would improve segregation of costs by seasons. **However, customer considerations suggest that maintaining two seasons, defined by the same months as the current seasons which have applied for more than thirty years, is preferable, when compared to the incremental complexity resulting from implementation of a third seasonal period.**
>
> Going forward with the RPS obligations to the year 2030 and beyond and with the continued increase in solar generation, **the months of October through February are expected to see a comparable deepening of the mid-day hourly cost curve** similar to the deepening trough for net load illustrated in Section A [of Chapter IV of Exhibit SCE-01].
>
> <u>Does the data actually support a shorter super off-peak season?</u>
>
> While separating the months of March through May would result in a more refined super off-peak period, **for simplicity, customer understanding, and to take into account the anticipated future evolution of the net load,** here SCE proposes that all non-summer months should be combined into one winter season, with a winter super-off-peak period from 8:00 a.m. to 4:00 p.m.
>
> <u>Does the data support more specifically targeted TOU periods?</u>
>
> **Customers also prefer fewer daily TOU periods in each season.** Currently, SCE customers have three TOU periods on summer weekdays. To respond to this customer preference, SCE's proposal limits TOU periods to no more than three periods in the summer or

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67 Exhibit SCE-01 at 67.

> winter. In addition, to promote customer acceptance of the revised TOU periods, SCE proposes the same TOU periods for weekdays and weekends, even though some cost differences could justify differentiation of a winter super off-peak period between weekdays and weekends, as discussed [herein].

We emphasize that we agree with SCE's analysis and reasoning because it is supported by SCE's data, and also shows that SCE takes seriously the real-world impacts on its customers who will be impacted by the changing seasons, and considered those impacts throughout its analysis. Finally, as will be seen below SCE for the most part anticipated—and addressed in the text we just quoted—the objections to its super off-peak proposal subsequently raised by SEIA in its prepared testimony.

ORA agrees with SCE's proposal to establish a winter season super off-peak period, but recommends a duration of 8 a.m. to 3 p.m., ending one hour earlier than SCE's proposal.[68]

In its April, 2017 testimony SEIA opposes SCE's proposal, but agrees that "there is a need for a program that offers discounted rates in those midday hours in the spring months when both net loads and energy prices are low, and when additional electric consumption would be useful in avoiding over-generation conditions and the curtailment of renewable resources."[69] However, because these conditions are not expected to be present on every spring day, or on every winter season day, SEIA sees no need for a super-off-peak TOU period every day.

SEIA states that it "prefers the more targeted alternative of developing an optional 'Discount Days' program to deal with specific periods of low prices in the middle of the day… Such a program would offer customers a discounted price in

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68 Exhibit ORA-1 at 3.

69 Exhibit SEIA-01 at 24.

the midday periods of a limited number of event days, called a day in advance, when prices are expected to be low, renewable supplies will be abundant, and over-generation risks are increased. In exchange, customers would pay slightly higher prices in other TOU periods, in order to keep the program revenue neutral."[70]

In its rebuttal testimony, SCE first asserts that SEIA's Discount Days concept is outside the scope of this proceeding, because it addresses rate design and not the establishment of standard TOU periods.[71] SCE is correct, and we have not considered this rate design proposal in this decision.

Second, SCE responds to SEIA's opposition to a winter season-long super-off-peak period by referring back to the guiding principles and methodology that it followed and that led it to make this proposal:

> SCE's proposed TOU periods are based on the clustering of hours when costs, on average, are expected to be fairly consistent […] The establishment of a super-off-peak period and the accompanying retail rate design also allows customers to actively participate in modifying consumption behavior in a manner that alleviates CAISO-system-level operating constraints that are caused by oversupply conditions typically prevalent in SCE's proposed super-off-peak period, as discussed in Exhibit SCE-02.[72]

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[70] *Ibid.*

[71] Exhibit SCE-03 at 44.

[72] *Ibid.* SCE cites Exhibit SCE-02 at 14, wherein SCE discusses how its proposals in this proceeding address certain aspects of the Commission's DER Action Plan. SCE notes that one element of the DER Action Plan relates to "appropriate rate designs to absorb oversupply" and explains that

> Exhibit SCE-1 acknowledged this "oversupply" condition in historically high demand hours, and the corresponding testimony examines the pricing impacts associated with changes in the system "net load." **As a result, SCE proposes modifications to its current base TOU periods to better address this oversupply condition by creating a super-off-peak period in the winter season to encourage consumption during the most likely periods of over-supply.** SCE's 2018 GRC

Footnote continued on next page

The PD essentially adopted SCE's proposed super off-peak period when it adopted the whole of SCE's proposed TOU periods. However, comments on the PD rightly observed that the PD provided no explanation for adopting SCE's super off-peak period; we address those comments below.

8.2.2. Comments on the PD

In its opening comments, SEIA argues that the PD errs in its adoption of SCE's proposed super-off-peak period for two reasons.

First, according to SEIA the proposed super-off-peak period is actually comprised of varying periods with significantly different marginal costs. SEIA examines SCE's explanation that its proposed TOU periods are based on the clustering of hours when costs, on average, are expected to be fairly consistent and asserts that "to the contrary, it illustrates a marked cost difference between the 8:00 a.m. to 4:00 p.m. time period during the months of October through February and the comparable time period during the months of March through May."[73]

SEIA's second argument against SCE's proposal is that it is inconsistent with the objective of such a TOU period: promoting consumption during a time period that could serve to alleviate CAISO-system level operating constraints that are caused by over-supply conditions.[74]

SEIA concludes by recommending the PD be modified such that "the recommended super off peak period which would run from 8:00 a.m. to

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Phase 2 application will further address this issue with updated rate designs and pricing (emphasis added).

[73] Comments of the Solar Energy Industries Association on the Proposed Decision on SCE's 2016 Rate Design Window Application, at 4.

[74] *Id.* at 6-8.

4:00 p.m. every day for eight months (October through May) must be limited to midday hours during the spring months (no more than March, April, and May)."[75]

CALSSA's comments on the PD support SEIA's comments. [76]

SCE addresses SEIA's arguments in it reply comments on the PD. First, SCE observes that no party in this proceeding, including SEIA, proposed a spring season as SEIA proposed for the first time in its opening comments, so there is no evidentiary record to support its adoption by the Commission. Second, SCE faults SEIA's reliance on marginal energy costs alone to support its criticisms, because D.17-01-006 "very clearly found that the time sensitivity of all (cumulative) utility marginal cost elements, based on hourly patterns, is relevant in assessing TOU periods."[77] Third, SCE defends the results of its "clustering" methodology, stating

> SCE's proposed TOU periods, including the SOP period, are based on the clustering of hours when cumulative costs, on average, are expected to be fairly consistent [citing Exhibit SCE-01 at 58-65 and 73].
>
> SCE looked at the average costs of the SOP hours in the October through February period compared to March through May and found a minimal difference in costs (with the differences diminishing as we get closer to 2024) - resulting in SCE proposing a full winter SOP period [citing Exhibit SCE-01, Figure IV-27].
>
> Additionally, as further discussed in testimony, retaining only two seasons is preferable to customers and will make SCE's other

[75] *Id.* at 15.

[76] Comments of the California Solar and Storage Association on the Proposed Decision at 6.

[77] Southern California Edison Company's Reply Comments on Proposed Decision Regarding its 2016 Rate Design Window Application at 3, citing D.17-01-006, Finding of Fact 15 ("Marginal generation costs, consisting of marginal energy costs and marginal generation capacity costs, constitute the primary basis for setting TOU periods, but the time sensitivity of all utility marginal cost elements, based on hourly patterns, is relevant in assessing TOU periods.").

> proposed changes in TOU periods easier for customers to understand and accept [citing Exhibit SCE-01 at 68]

Fourth and finally, SCE objects to SEIA's reliance on the CAISO analysis prepared for R.15-12-012, and SEIA's citation to the TOU periods recently adopted or settled on for other utilities. SCE asserts that this is not consistent with D.17-01-006:

> CAISO is not a party to this proceeding and made no specific proposals related to the TOU periods that should be adopted for SCE's service territory.
>
> TOU periods adopted for other utilities are also not a consideration in the policy guidelines adopted in the TOU OIR. Rather, Policy Guideline No. 1 states that "[b]ase TOU periods and related rate designs should be established ***independently*** for each utility" (emphasis added by SCE), and Policy Guideline No. 2 then states "[b]ase TOU periods should be based on <u>***utility-specific***</u> ***marginal costs, rather than on a statewide load assessment***" (emphasis added by SCE). SCE's proposed TOU periods fully comply with these guidelines, as recognized in the PD.[78]

SEIA also submitted reply comments on the PD, but simply repeated the arguments made its opening comments. Rule 14.3(d) of the Commission's Rules of Practice and Procedure requires that replies to [opening] comments on a proposed decision shall be limited to identifying misrepresentations of law, fact or condition of the record contained in the comments of other parties. Therefore, we disregard SEIA's reply comments because they do not cite the opening comments of other parties regarding the proper super off-peak period.

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[78] *Id.* at 4. In footnote 15, SCE adds a noteworthy clarification regarding the CAISO analysis prepared for R.15-12-012 : "the CAISO analysis referenced in SEIA's comments is for TOU periods <u>targeting only a 33 percent Renewables Portfolio Standard (RPS) requirement by 2021</u> (which is increasing to 50 percent due to the passage of Senate Bill 350 and will likely deepen the belly of the duck in SCE's proposed SOP period). <u>SCE's analysis is based on a 2024 reference year (with its higher RPS requirement of 40 percent</u>)…".

8.2.3. Discussion of Super Off-Peak Proposals

A noteworthy aspect of this proceeding has been the repeated instances where several parties examine an identical data set but draw significantly different conclusions from that data. Here, both SCE and SEIA cite the same Figures IV-27, IV-28 and IV-29 in Exhibit SCE-01 to illustrate the merits of their conflicting positions regarding the proper super off-peak period for SCE. We have reviewed the same figures, as well as the analyses undertaken by SCE and SEIA. On that basis, we see no reason to change the determination in the PD that SCE's proposed super off-peak period should be approved.

The series of Figures in question illustrate the iterative nature of SCE's analysis. We begin by providing SCE's Figure IV-27 below, along with SCE's accompanying text:

> Figure IV-27, below, categorizes by two shades of green the lowest-cost hours and months and adds those results to the two shades of red that were used in Figure IV-25 to categorize the selection of the highest-cost hours and months. The dark green color identifies the lowest-cost "core" hours from March through May, and the lighter green color identifies the lower-cost hours occurring from October through February but displays similar cost characteristics to the months from March through May. The average cost for these two lowest-cost TOU periods is shown in $/kWh inside each of the two low-cost periods, i.e., $0.046/kWh for October through February and $0.031/kWh for March through May.[79]

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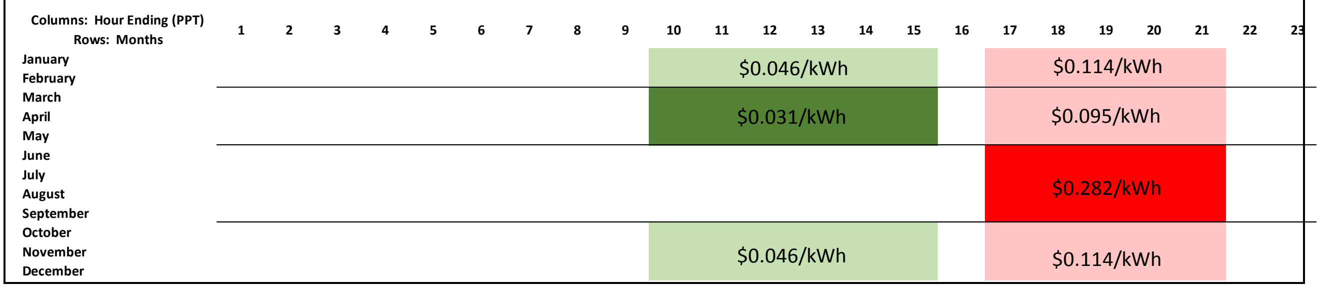
[79] Exhibit SCE-01 at 61.

Figure IV-27
Interim Selection of TOU Periods and Months for Lowest and Highest-Cost Hours



In its comments on the PD, SEIA refers to Figure IV-27 and asserts that it does not support SCE's super off-peak proposal: "to the contrary, it illustrates a marked cost difference between the 8:00 a.m. to 4:00 p.m. time period during the months of October through February and the comparable time period during the months of March through May."[80] SEIA states that while the difference between an average cost of $0.046/kWh during the 8:00 a.m. to 4:00 p.m. time period in the months of October through February and $0.031/kWh during the comparable time period during the months of March through May might appear minimal,

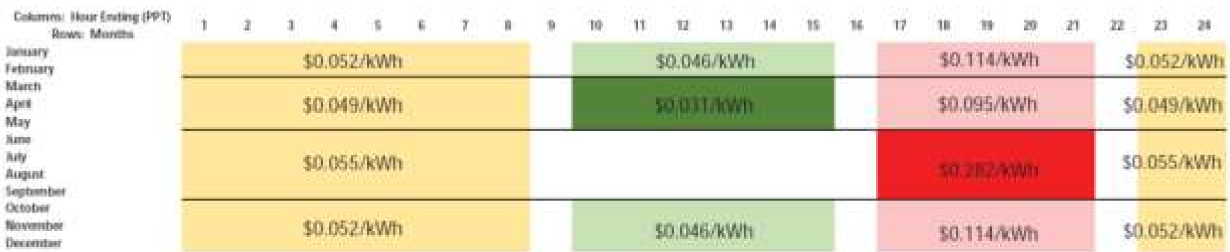
> these costs are primarily comprised of marginal energy costs (MECs). MECs in the midday hours of the winter months are typically $0.03 to $0.05 per kWh. The $0.015 per kWh difference in MECs translates into the October through February MECs during the midday period that are 50 percent above the MECs for the comparable time period during the months of March through May. This is not a minimal difference, as depicted by SCE.[81]

SEIA then cites Figure IV-28 of Exhibit SCE-01 to complete its quantitative critique of SCE's proposed super-off-peak period:

[80] SEIA Comments at 4.

[81] *Id.* at 4-5, internal footnotes omitted.

Figure IV-28
Interim Selection of High-Cost (Red), Low-Cost (Green), and Mid-Range (Yellow) Cost Periods



> Figure IV-28 of Exhibit SCE-01 provides an even fuller picture, providing the average marginal costs during the winter off-peak hours from the late evening to early morning, for comparison to the midday costs shown in Figure IV-27. This figure further highlights the incongruity of grouping the $0.046/kWh 8:00 am to 4:00 p.m. time period in October through February with the $0.031/kWh 8:00 am to 4:00 p.m. time period in March through May. This Figure shows that the $0.046/kWh 8:00 am to 4:00 p.m. time period in October through February is much closer to the costs of $0.052/kWh in the off-peak hours of 9:00 p.m. to 10:00 a.m. for those same months than to the $0.031/kWh 8:00 a.m. to 4:00 p.m. time period in March through May. Thus, from a cost perspective, the hours of 8:00 a.m. to 4:00 p.m. during the months of October through February are more accurately grouped as off-peak hours than super off-peak.[82]

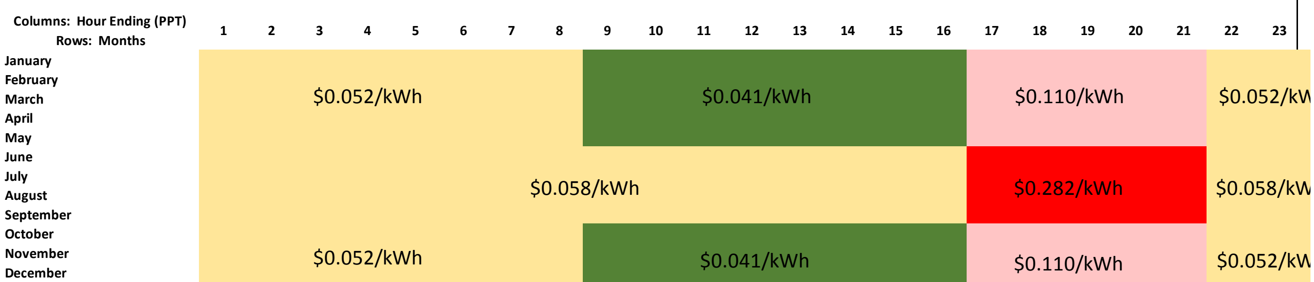
SEIA also opposes SCE's proposal on qualitative grounds, arguing that it is important that the choice of TOU periods should result in meaningful rate differences between the selected periods:

> A SOP rate which is relatively close to the off-peak rate fails to send an effective price signal. There is no purpose served by TOU periods that have rates that are similar - this confuses customers and complicates the rate structure while not proving any reason to take actions based on such small differences. Figure IV-29 of Exhibit SCE-01 shows that

[82] *Id*. at 5.

> SCE's proposal for an SOP in all eight winter months results in a winter SOP rate that is just $0.01 per kWh lower than the winter off-peak rate; whereas Figure IV-28 shows that the difference is about twice as large if the SOP is limited to the three months of March to May. Finally, the record shows that that this problem is even worse if one looks at current (2015 or 2017) marginal costs.[83]

Figure IV-29
Interim Selection of High-Cost (Red), Low-Cost (Green), and Mid-Range (Yellow) Cost Periods



Like SCE, we do not draw the same conclusions as SEIA from the data, as represented in the Figures reproduced above. Viewed with reference to the guiding principles adopted in D.17-01-006, we agree with SCE's analytical logic and its supporting qualitative analysis.

First, in D.17-01-006 we found to be reasonable "the general principles currently used by each of the IOUs to determine the number of seasons (and months within those seasons) used for TOU rate purposes" and agreed that the seasons and months included therein for setting TOU rates should be a utility-specific inquiry based on marginal costs.[84] SCE's proposals, even though submitted months prior to D.17-01-006, were developed in a manner consistent with that decision.

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[83] *Id.* at 6.

[84] D.17-01-006 at 32-33.

Second, as we noted at the outset of this decision, one of the guiding principles adopted in D.17-01-006 provides that TOU periods used in rate designs should be designed around Base TOU periods and should reflect up-to-date marginal costs, but may be modified to take into account customer acceptance, preferences, understanding, ability to respond and similar factors, including:

- The ability of customers to respond at a specific time of day or over a given period of time.
- Customers' need for predictable TOU periods, including the schedule of possible TOU rate period changes, when they make investment decisions regarding energy efficiency, storage, photovoltaics, electric vehicles and other distributed energy resources or consider major operational changes to shift usage outside of peak periods.[85]

The second bulleted point listed above warrants further discussion, because its significance is subtle but key to our determinations herein. We devoted considerable discussion in D.17-01-006 to the length of time that newly adopted TOU periods should remain in effect. We noted that there are significant marketing, education and outreach costs inherent in adequately communicating with customers about a change to TOU periods, and we agreed with "the consensus [among parties] that after TOU interval periods are set they should remain fixed for a reasonable period of time before being subject to modification. Frequent changes to TOU rate periods could make TOU rates less effective in motivating customers to shift load to off peak hours."[86]

[85] *Id.*, Appendix 1, "Policy Guidelines Applicable to the Design, Implementation, and Modification of Time-of-Use (TOU) Periods To be Used in Rate Designs," Guideline Number 9.

[86] *Id.* at 45.

For these reasons, we find that establishing a super off-peak period for SCE's entire winter season between the hours of 8:00 a.m. to 4:00 p.m. is the best means of assuring that the TOU periods that we adopt in this decision remain fixed for a reasonable period of time before being subject to modification. SCE's proposal aligns more logically than SEIA's with the possibility that California's RPS requirements may continue to increase. Qualitatively, we find that customer acceptance of a winter-long period, with a smaller cost differential, is more likely in comparison to a springtime-only period with a sharper differential. Finally, the proper forum to evaluate and possibly adopt departures from Base TOU periods is SCE's rate design proceeding, not here. We find that it is preferable to adopt a simpler, milder and more stable super off-peak period here and consider any specific rate design proposals in SCE's A.17-06-030 or subsequent proceedings.

8.3. Conclusion

Based on our extensive review of the evidentiary record above, we find that SCE's analysis fully supports its proposed TOU periods, and we conclude that they should be adopted. We determined above that SCE's use of a 2024 forecast was reasonable; we also found that SCE's resulting marginal cost estimates were methodologically sound. As such, our reliance upon the extension of those results into SCE's determination of new Base TOU periods is reasonable and well-supported by SCE's testimony. The adopted TOU periods are shown below in Table 3-A (weekdays) and Table 3-B (weekends).

Table 3-A
Adopted TOU Periods (Weekdays)

TOU Period	Summer (June – September)	Winter (October – May)
On-peak	4 p.m. - 9 p.m.	
Mid Peak		4 p.m. - 9 p.m.
Off-peak	All hours except 4 p.m. -	9 p.m.- 8 a.m.

	9 p.m.	
Super-off-peak		8 am - 4 p.m.

Table 3-B
Adopted TOU Periods (Weekends)

TOU Period	Summer (June – September)	Winter (October – May)
On-peak		
Mid Peak	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.
Off-peak	All hours except 4 p.m. - 9 p.m.	9 p.m.- 8 a.m.
Super-off-peak		8 am - 4 p.m.

9. TOU Period Grandfathering

D.17-01-006 established the qualifying attributes of customers who are entitled to remain on existing TOU periods during a five or ten-year transition depending on the customer type. As described in Ordering Paragraph 5 of D.17-01-006, for non-residential systems, this transition continues for ten years after issuance of a permission to operate, but in no event shall the duration continue beyond December 31, 2027 (for schools) or July 31, 2027 (for all other non-residential). Ordering Paragraph 5 of D.17-01-006 is binding on this proceeding and we do not revisit the TOU grandfathering duration adopted therein.

10. Other Mitigation Measures: RES-BCT

In D.17-01-006 the Commission specified that new TOU periods should be introduced in a manner that reduces or mitigates negative impacts on customers. The Commission ordered the utilities to ensure that customers with existing behind-the-meter solar be permitted to maintain their existing TOU rate periods for five years (residential customers) or ten years (non-residential customers).[87]

[87] D.17-01-006, Ordering Paragraph 5.

The Commission also permitted the utilities to structure an alternative but equivalent mitigation measure for these customers, subject to approval by the Commission.[88]

Several water agencies and water districts intervened in this proceeding in order to request grandfathering or another mitigation measure responsive to their particular circumstances.[89] All the REWDs have a number of renewable energy generation projects, which are either Net Energy Metered (NEM) or participating in the Renewable Energy Self-Service Bill Credit Transfer program (RES-BCT). The REWDs seek relief in this proceeding due to the anticipated effects of SEC's proposed TOU periods on RES-BCT.

The RES-BCT program was established by the legislature effective January 1, 2009, and is codified in Section 2830 of the Public Utilities Code. Assembly Bill 512, signed into law in 2011 and effective on January 1, 2012, further modified the program to increase the generator size limit to 5 MW per generation account. The RES-BCT program allows governmental entities, who may not have electric loads where the potential for renewable generation exists, to nevertheless install renewable energy generation projects in those locations. The program allows local governments to generate energy from an eligible renewable generating facility for its own use ("generating account") and to export energy not consumed by the generating account to the electrical grid. Any energy exported by the renewable generating facility to the grid is calculated into bill credits and applied monthly to the designated benefiting account(s). The value of the credit

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[88] *Ibid.*

[89] These parties are Castaic Lake Water Agency, Eastern Municipal Water District, and Rancho California Water District (hereinafter Renewable Energy Water Districts, or REWDs).

for the exports to the grid from the renewable generator (generating account) is established using only the generation component of the TOU energy charge of the generator account rate schedule. This differs from the NEM tariff, which provides project owners a credit equal to the entire retail rate. Thus, RES-BCT generation credits are heavily dependent on the peak hour pricing structure of SCE's TOU periods.[90]

This structure of the RES-BCT credit mechanism has the result that, if SCE's proposed TOU period changes are adopted, the REWDs will experience a "breathtaking" loss in the value of the solar energy produced by their projects.[91] For this reason, the REWDs request that the Commission allow solar RES-BCT projects to remain on current TOU periods for 20 years from their PTO (Permission to Operate) date. Alternatively, the REWDs request that the Commission establish a "fixed indifference payment protocol" that would be available to behind-the-meter solar projects at the customer's discretion. The protocol would provide an indifference payment of the net present value of the financial impact of TOU period changes for the duration of the grandfathering period.

SCE argues that requests for additional grandfathering must be made through petitions for modification (PFM) of D.17-01-006, not in this utility-specific RDW. SCE also asserts that the other mitigation measures proposed by the Water Districts are contrary to the spirit of the August 9, 2017 ALJ Ruling on Motions to Strike, which held that testimony should be "stricken if the testimony proposes specific rate design changes or other 'mitigation' measures, so that those proposals could be considered with all other rate design proposals in SCE's GRC Phase 2

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90 Exhibit CLWA-01 at 2.

91 REWD Opening Brief at 3. *See also*, Exhibit RCWD-01 at 2, citing losses of $280,000 per year and Exhibit CLWA-01 at 2, citing losses of $350,000 per year.

application, A.17-06-030." For example, SCE and the Agricultural Parties stipulated earlier in this proceeding that the Agricultural Parties' mitigation concerns will be addressed in SCE's pending 2018 GRC Phase 2 proceeding.

EUF argues that providing mitigation beyond already-adopted TOU period grandfathering would be unfair to other customers. EUF suggests that the water districts have not justified that they deserve additional compensation, because if a change to TOU periods was not anticipated, RWCD and REWD did not use all available information, relied on an expert who did not have timely awareness of the duck curve, relied on vendor financial estimates, and have not exhausted other avenues of relief.[92]

10.1. Discussion

When passed in 2008, the intent of AB 2466 was "to allow local government entities to credit energy produced from renewable resources owned by the local entity against their electricity usage on more than just the facility where the renewable generator is located."[93] Section 2830 (f) required SCE to file an advice letter that complied with Section 2830, "proposing a rate tariff for a benefiting account" and required this Commission to approve the proposed tariff, or specify conforming changes to be made and filed in a new advice letter.

Evidence in this proceeding demonstrates that if we simply approve SCE's new TOU periods and take no further mitigating actions, we will have contravened the intent of the Legislature by effectively shutting down the program

[92] EUF Opening Brief at 9-12. EUF makes unsupported assertions that vendors are "not necessarily neutral, can ignore potential risks and can be optimistic" and states that "this calls into question the diligence used in investigating the projects." We found the REWD witnesses to be entirely credible, and we give no weight here to EUF's unsupported statements.

[93] *See*, e.g., Senate Energy, Utilities and Communications Bill Analysis, June 18, 2008 and Assembly Floor Analysis, August 14, 2008.

that we were directed to create when the Governor signed AB 2466. SCE and EUF, by opposing some form of relief for the Renewable Energy Water Districts ignore this simple reality of California law. SCE also misreads D.17-01-006 if it believes that decision precluded customers on its RES-BCT tariff from receiving mitigation beyond the ten-year grandfathering period provided by Ordering Paragraph 5 of that decision. As we made clear earlier in D.17-01-006, "although today's decision adopts grandfathering for a specific situation, we expect that going forward the IOUs, customers, and DER technology providers will develop mitigation measures that are more transparent and more narrowly tailored than grandfathering."[94] To be consistent with D.17-01-006 and in order to continue to comply with the legislative intent behind Section 2830, in today's decision we direct that SCE and the Renewable Energy Water Districts work collaboratively in SCE's currently-open GRC Phase 2 proceeding (A.17-06-030) to develop an indifference mechanism that, by mutual agreement, will have the result that the RES-BCT program continues to be a viable mechanism for the governmental entities that entered the program in good faith that it would not be effectively canceled part-way through the life of the investments they made to participate in California's efforts to reduce greenhouse gas emissions and help achieve the state's climate goals.[95]

11. Implementation of Adopted TOU Periods

In rebuttal testimony, SCE responded to various parties' concerns about a "dual" implementation of its new TOU periods in October, 2018 followed shortly

[94] D.17-01-006 at 48.

[95] Exhibit RCWD-01 at 2-4 and Exhibit CLWA-01 at 3

thereafter by new GRC Phase 2 rates. In response to that concern, SCE proposed a single February 2019 implementation date for both proceedings.

We adopt parties' preferred implementation date and direct that new TOU periods established in this proceeding shall begin no sooner than February 2019 and shall be implemented concurrently with any rate changes adopted in SCE's GRC Phase 2 proceeding.

12. Critical Peak Pricing (CPP)

As SCE notes in its application, the highest system marginal costs are often concentrated in a few hours throughout any given year and are driven by high temperature conditions, which generally occur during the summer. To more accurately assign these energy and capacity costs to the few days and hours in each year with highest system load conditions, the Commission has established dynamic pricing rates, such as the CPP and RTP programs.[96]

SCE made a number of CPP-related proposals in this proceeding:

- Redefine its CPP event periods to align with its proposed TOU periods;
- Redesign certain CPP program elements; and
- Implement default CPP for eligible TOU-GS-1, TOU-GS-2, and TOU-PA-3 customers.

In addition, "based on recent developments and information concerning the cost and efficacy of default CPP" SCE made an alternative proposal that requests optional (as opposed to default) CPP for its small commercial customers.[97]

SCE proposes that these changes take effect on the same date as the rest of this decision in order to align with the adopted TOU periods and to allow customers to adjust to the new rate structures before CPP events are called the following summer.

SCE's alternative proposal provides that SCE would continue to provide opt-in enrollment for TOU-GS-1 customers in the revised CPP program, while maintaining the required transition for TOU-GS-2 and TOU-PA-3 customers to

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[96] SCE Application at 9.

[97] *Ibid.*

default CPP. SCE asserts that the alternative treatment for TOU-GS-1 customers is reasonable because "the Commission's prior decisions did not take into account newer evidence that demonstrates commercial and industrial (C&I) customers with demands of less than 20 kW who were defaulted to CPP do not meaningfully contribute to load reductions in the on-peak period."[98] SCE asserts that, given the effort and administrative costs involved with defaulting TOU-GS-1 customers, and the "high likelihood" that they will not meaningfully contribute to the Commission's load impact objectives, the Commission should focus on other, more effective, means to encourage these customers to reduce load.

CLECA/CMTA, ORA, and CSBA/CSRBT support SCE's alternative proposal, but pursuant to the joint stipulation between SCE, Farm Bureau and AECA, SCE supports extending its alternative proposal (*i.e.*, CPP being offered as an optional rather than a default rate) to TOU- PA-3 customers as well. SCE asserts this is reasonable given the unique characteristics of agricultural customers and the relatively small amount of load served under the TOU-PA-3 rate schedules.

We find that we should approve SCE's proposed changes to its CPP rates.[99] However, we deny without prejudice SCE's alternative proposal to offer CPP as an optional rather than a default rate to customers on its TOU-GS-1 and TOU-PA-3 rate schedules. First, SCE seeks to modify the requirements of D.16-03-030, and we decline to do so based on the record before us. Because SCE relies on results in PG&E's territory, our record would have benefitted from more

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[98] Exhibit SCE-01 at 103.

[99] Customers with pending Direct Access (DA), Community Choice Aggregation (CCA), or Community Aggregation (CA) enrollments shall not be defaulted to CPP as SCE's CPP program is a generation-rate program for which only Bundled Service customers are eligible.

analysis and explanation around the question of why PG&E experienced the results it reported, and why those results should inform our decision on SCE's request. SCE also suggests that it would be costly to implement default CPP for the affected customer groups, but provides little supporting analysis. As such, procedurally, if SCE wishes to pursue its request further the proper route is a petition for modification of D.16-03-030. This would allow the Commission to re-consider SCE's alternative CPP proposal prior to the implementation date for the instant decision.

The CPP changes authorized in this decision shall be implemented on the same date as other proposals in this decision no sooner than February 2019 and shall be implemented concurrently with any rate changes adopted in SCE's GRC Phase 2 proceeding.

13. Real-Time Pricing (RTP)

As SCE notes in its application RTP tariffs provide customers with more accurate and granular energy price information, allowing customers to tailor energy usage and save on energy bills by more precisely avoiding high-cost period usage and conversely, increasing usage during low-cost periods. SCE requests authority to simplify and revise its RTP tariffs in order to better align the price profiles of those rates to actual costs, and to encourage greater customer participation.

In testimony, SCE explains that its current RTP schedules offer menus of hourly prices to non-residential customers that reflect hourly marginal energy and capacity costs, aggregated into nine seasonal 24-hour price sets, which differ based on season, day type (workday versus weekend), and temperature. This structure was first implemented in 1988, and has remained largely unchanged. SCE states that because its RTP pricing structure provides strong cost signals to customers and encourages demand response, SCE's RTP customers have provided significant load reductions during system peak hours.

SCE also explains how its proposals in this proceeding will affect its RTP pricing structure. First, temperature will continue to be the trigger for RTP date types, because temperature remains highly correlated with SCE's system peak demands. Second, implementation of forecast 2024 marginal generation costs would result in RTP rates with high cost hours shifted to later in the day and concentrated in "far fewer" hours. Third, introduction of the 2024 marginal generation costs also changes the shape of the RTP rates from a "bell curved" price shape to a "duck curve." In addition, introduction of flexible capacity results in an allocation of generation capacity costs to every RTP day type, unlike the current RTP rates which do not allocate any generation capacity costs to winter or weekend days.

Given the above impacts on SCE's current RTP schedules, SCE proposes to simplify the RTP rate structure and (possibly) increase program enrollment by condensing the current five-tier summer weekday prices into three day-types. Thus, summer weekday types would consist of three price tiers for: (1) temperatures below 80 degrees, (2) between 81 – 90 degrees, and (3) above 90 degrees.

SCE explains that reducing the number of summer day types results in a reduction of the summer hottest day's peak price from $9.30/kWh to $3.80/kWh, which is much closer to today's peak price of $2.50/kWh. SCE acknowledges that "while the current distribution of day types provides greater price granularity, prices in the highest temperature day have often proved to be a barrier when marketing to customers. Therefore, softening the peak prices is a reasonable compromise between precision and customer acceptance."

SCE also provides bill impact analyses for its proposed changes, which we summarize below:

- 75% of current RTP customers will not be significantly impacted by the changes (i.e., a bill impact between -5% and 5%);
- 13% of current RTP customers already have usage patterns that align well with the 2024 price profile, and will see a bill reduction; and
- 12% of current RTP customers will be negatively impacted by the proposed changes.

Regarding the negatively impacted group, SCE notes that these customers have historically been very responsive to RTP price signals, such that although their current usage patterns have been optimized to respond to current RTP price profiles, these bill impacts do not account for customer's [likely] responses to the new price profiles and do not reflect the expected actual bill after the new RTP rates are implemented. In short, SCE expects that this third group of customers will actively shift load in response to anew 2024 RTP price profile.

No party opposed SCE's RTP proposals.

We find that SCE's proposed changes to its RTP rate design are well supported by the evidence and SCE's analysis, and we authorize the proposed changes. These authorized changes shall be implemented on the same date as other proposals in this decision, no sooner than February 2019 and shall be implemented concurrently with any rate changes adopted in SCE's GRC Phase 2 proceeding.

14. Marketing, Education, and Outreach (ME&O)

SCE proposed a ME&O campaign for its new TOU period roll-out in direct testimony. While that proposal was challenged in part by SBUA, those differences were resolved through the joint stipulation between SCE and SBUA. With the clarifications and additions provided for in that stipulation, SCE requests that its ME&O plan be approved in its entirety.

We approve SCE's proposed ME&O campaign for its new TOU period roll-out, with the clarifications and additions provided for in the stipulation the joint stipulation between SCE and SBUA.

15. Distributed Energy Resources (DER) Action Plan

On November 10, 2016 the Commission endorsed a "Distributed Energy Resources Action Plan" (DER Action Plan). Distributed energy resources are defined as distribution-connected distributed generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies. The purpose of the DER Action Plan is to continue the Commission's support of DER by accomplishing four objectives:

1. Provide a long-term vision for DER and supporting policies;
2. Identify continuing efforts in support of the long-term vision;
3. Assess and direct further near-term action needed to support long-term vision; and
4. Establish a DER coordinating committee responsible for sustained coordination of DER activities.

To accomplish this purpose, the DER Action Plan endorses a strategic scope and structure, including three groups of related proceedings or initiatives:

1. Rates and Tariffs;
2. Distribution Grid Infrastructure, Planning, Interconnection and Procurement; and
3. Wholesale DER Market Integration and Interconnection.

The DER Action Plan includes "vision," "continuing," and "action" elements for each proceeding grouping.[100] Within the Rates and Tariffs group, five vision elements are identified:

A. A continuum of rate options, from the simple to complex, is available for customers, and customers are educated to make informed choices;

B. Rates reflect time-varying marginal cost;

C. Processes for adopting innovative rates and tariffs are flexible and timely;

D. Rates and demand charges better reflect cost causation and capacity benefits of DERs; and

E. Rates remain affordable for non-DER customers.

The DER Action Plan states that the Commission is actively considering augmentations and refinements to many DER policies in Commission proceedings. Specifically, the DER Action Plan identifies "consideration of fixed charges, TOU periods and rates, nonresidential rate design, including enhancements to dynamic rates" as a "continuing" element in Rate Design Window and GRC Phase 2 proceedings, as well as "appropriate rate designs to absorb renewables oversupply."

The Scoping Memo for this proceeding determined that in order to provide information necessary to help the Commission align its vision and actions to shape California's distributed energy resources future, the record in this proceeding should be supplemented to include input from SCE and other parties regarding how SCE's application addresses any or all of the vision and continuing elements identified within the Rates and Tariffs group of the DER Action Plan. SCE was

[100] The "continuing" elements are ongoing efforts that help achieve the vision. "Action" elements are additional efforts considered necessary for achieving the vision.

directed to serve responsive testimony, and intervenors could then address SCE's testimony in their rebuttal and reply testimony.

SCE asserts that its supplemental testimony (Exhibit SCE-02) demonstrated how SCE's proposals in this proceeding meet the applicable "vision" and "continuing" elements of the DER Action Plan. For example, SCE demonstrated that its TOU proposals reflect the time-variation of marginal costs and that, overall, sending customers economically-efficient price signals "will help compensate DER customers fairly while helping to maintain non-DER customer affordability."[101] SCE testified that its new proposed TOU periods would encourage certain kinds of DER adoption, namely energy storage.[102] SCE also placed the DER Action Plan into the Commission's overall policymaking context by noting that specific rate designs and potential mitigation measures as they relate to DERs as a result of the new TOU periods adopted in this proceeding have either already been decided in D.17-01-006 or will be decided in SCE's pending 2018 GRC Phase 2 proceeding, A.17-06-030.

We acknowledge the effort made by SCE to demonstrate how SCE's application addresses the vision and continuing elements identified within the Rates and Tariffs group of the DER Action Plan. SCE's explanation of how DER-related rate designs and potential mitigation measures resulting from the TOU periods adopted in this proceeding are interrelated with other proceedings is invaluable information that we will rely upon to coordinate the outcomes of the various proceedings that affect DER, either directly or indirectly.

16. Option R Cap

[101] Exhibit SCE-02 at 9.

[102] RT at 92-93.

SCE's Option R rate schedules are available to commercial and industrial customers with demands greater than 20 kilowatts (kWs) but not exceeding four megawatts (MW), and who employ Renewable Distributed Generation Technologies.[103] Option R rates feature reduced demand charges and correspondingly higher volumetric TOU rates, a rate structure that is attractive to solar customers.

The Commission first adopted Option R in D.09-08-028, which approved a settlement resolving SCE's 2009 GRC Phase 2 proceeding. As part of the settlement, subscription on Option R was limited to a cumulative installed distributed generation output capacity of 150 MW for all eligible rate groups:

> An experimental rate shall be offered as an optional rate schedule for customers with demands greater than 20 kW but not exceeding 4 megawatts (MW) and who employ Renewable Distributed Generation Technologies. Participation in Schedules TOU-8-R, GS-2-R and TOU-GS-3-R shall be limited to a cumulative installed distributed generation output capacity of 150 MW.[104]

The Commission subsequently authorized an increase in the level of the Option R cap in D.14-12-048, its decision addressing a settlement in SCE's 2013 RDW proceeding. The revised level of the cap was 400 MW:

> Between the date on which this Settlement Agreement is approved by the Commission, and the date on which SCE's tariffs implementing its 2018 GRC Phase 2 are effective, subscription on Rate R shall be subject to a cumulative installed generation output capacity for all eligible rate groups of 400 MW total, inclusive of all customers currently

[103] This term is defined as solar, wind, fuel cells, and any other renewable generation technology as defined in the Statewide California Solar Initiative, the Self-Generation Incentive Program, or their successors.

[104] D.08-09-028 at 22. See also Phase 2 Medium And Large Power Rate Group Rate Design Settlement Agreement, Section 4.b.d., "Experimental Schedule For Renewable Generating Technologies."

> taking service on the Special Solar Allowance of Schedule TOU-8 who switch to Rate R no later than six months after rates implementing this Settlement Agreement become effective.[105]

In that proceeding, the settling parties described this aspect of the settlement as follows:

> The proposed Rate R cap of 400 MW is a reasonable compromise between SCE's position (to maintain the fully subscribed cap "as is") and that of SEIA and CALSEIA's (to dispense with the cap entirely).
>
> By agreeing not to revisit the Rate R cap until SCE's 2018 GRC Phase 2, the Settling Parties simplify the scope of SCE's 2015 GRC Phase 2 (conserving resources and time for all affected parties).
>
> The Setting Parties also reached a compromise that they expect will provide certainty over a three-year horizon while rate design issues for solar customers continue to be evaluated in other proceedings (including the NEM rulemaking (R.14-07-002), to address issues pursuant to a schedule set forth in AB 327).[106]

CALSEIA protested SCE's application in the instant proceeding and asserted that its scope should include consideration of eliminating the cap on SEC's Option R tariffs. CALSEIA stated that "it is now apparent that the cap will likely be exhausted before the conclusion of the 2018 GRC. The instant proceeding is therefore the appropriate venue to consider raising or eliminating the cap on

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[105] D. 14-12-048, Ordering Paragraph 1. See also Settlement Agreement Resolving Southern California Edison Company's 2013 Rate Design Window Application, Section 4.c., "Rate R Megawatt Cap." CALSEIA was not a party to the Settlement Agreement, but authorized the settling parties to represent to the Commission that while it was not a signatory to the Settlement Agreement, it did not intend to file comments opposing it.

[106] August 14, 2014, Joint Motion of Southern California Edison Company, the Office of Ratepayer Advocates, the Solar Energy Industries Association, and the Natural Resources Defense Council for Approval of Settlement Agreement, at 14.

Option R."[107] The Scoping Memo did include this issue in the scope of this proceeding, finding that good cause existed for doing so:

1. CALSEIA was not a party to the 2013 RDW settlement, but its members are directly impacted by the cap agreed upon in that settlement;
2. CALSEIA presented a reasonable argument that
   i. the cap could be reached sooner than it can be addressed in SCE's 2018 GRC Phase 2, and
   ii. reaching that cap will present real-world difficulties to SCE customers who are interested in taking service under Option R rates; and
3. The Commission would not be disturbing the give-and-take of the 2013 RDW settlement simply by taking up the issue sooner than anticipated by the settlement.

Since the Scoping Memo was issued in March 2017, we have more recent record evidence on actual progress toward meeting the cap. Furthermore, SCE filed its 2018 GRC Phase 2 application on June 1, 2017 (A.17-06-030), where SCE proposes to replace Option R with a new "Option E", which SCE describes as "similar in that it would recover generation and a portion of distribution capacity costs through energy charges, but it is based on the updated TOU periods" proposed by SCE in this RDW proceeding (i.e., the periods that we have now adopted in this decision). We take notice of the fact that some parties in A.17-06-030 support SCE's proposal, while other parties, including CALSEIA/CALSSA, served testimony in opposition to the proposal. The Scoping Memo in that proceeding anticipates a Commission decision on SCE's application in December 2018.

SCE opposes raising the cap in this proceeding on policy grounds and because it believes it demonstrated that it is unlikely that the Option R cap will be

[107] October 7, 2016, Protest of the California Solar Energy Industries Association at 3.

reached before the implementation of new GRC Phase 2 rates in early 2019, so there is no need for the Commission to reach a determination of the issue here.[108]

EUF argues that this RDW is not the proper forum for changing the cap, asserting that there are open questions regarding the cost shift associated with Option R, which are properly addressed in the SCE's GRC Phase 2. Until that issue is fully evaluated, EUF believes it is premature to determine whether the Option R cap should be increased, and if so, by how much.[109]

In addition to CALSEIA/CALSSA, SEIA recommends that the Commission "lift the cap, at least temporarily, until further deliberation in SCE's 2018 GRC is concluded, if not permanently."[110]

16.1. Discussion

We find that we should leave the Option R cap undisturbed in this proceeding. Our approach to this issue is consistent with the Scoping Memo, in that we examine the questions of whether "the cap could be reached sooner than it can be addressed in SCE's 2018 GRC Phase 2" and whether "reaching that cap will present real-world difficulties to SCE customers who are interested in taking service under Option R rates." We weigh these considerations against the assertion in the Scoping Memo that "the Commission would not be disturbing the give-and-take of the 2013 RDW settlement simply by taking up the issue sooner than anticipated by the settlement."

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[108] *See* Exhibit SCE-03, pp. 67-68; *see also* SCE, Thomas, Evidentiary Hearing Tr. 1: 18; Exhibit SCE-104 at 6 (CALSEIA *ex parte* communication showing its estimate of trends for commercial NEM interconnections).

[109] Exhibit EUF-01 at 11-13 and EUF Opening Brief at 13-14.

[110] SEIA Opening Brief at 4.

Our main concern at this time remains whether the Option R cap will be reached before the Commission's decision in A.17-06-030 addresses the future of Option R. Based on the evidentiary record and official notice taken of more recent information as explained below, we find that this is unlikely to occur. This finding alone should put the matter to rest, because the answer to the question of whether "the cap could be reached sooner than it can be addressed in SCE's 2018 GRC Phase 2" is "no". Nevertheless, we provide further discussion here in order to assist parties in understanding our application of the facts at hand to the issue in question.

Neither the opponents of the cap nor its defenders came close to accurately predicted how quickly the cap might be reached. In testimony, CALSEIA noted that SCE's website reported that as of April 2017, 124.7 MW of "headroom" remained under the cap. CALSEIA calculated that at its estimated installation rate of <u>10 MW per month</u> the cap could be reached by April 2018 or sooner.[111] In rebuttal testimony served in June 2017, SCE cited participation levels since 2015 that showed approximately 13 MW of new installed capacity takes service on Option R each quarter, or <u>4.3 MW per month</u>.[112] At that rate, SCE estimated that it would take roughly 27 months to reach the existing 400 MW cap, by August 2019.

With the passage of time, more recent data have shown both CALSEIA and SCE to be off the mark. First, as noted above, in April, 2017 124.7 MW remained available under the cap. Second, in June, 2017 100.12 MW remained available.[113] Third, we take official notice of the most recent report on SCE's website, which

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[111] Exhibit CALSEIA-01 at 15.

[112] Exhibit SCE-03 at 67 and Figure IX-26.

[113] Exhibit CALSEIA-100, again providing the then-current report from SCE's website.

shows that 41.25 MW remained available as of June 6, 2018.[114] Thus, the cap has not been reached, as CALSEIA predicted[115] nor is capacity likely to remain available until August 2019, as SCE predicted.

Using data in the evidentiary record and the most recent data posted on SCE's website, we calculate that in the 11 ½ months between the June 2017 and June 2018 reports, available MW reduced by 58.9 MW, or 5 MW per month. At that rate, the 400 MW Option R cap would be reached in January, 2019: one month after the date the Commission expects to act on the proposals in A.17-06-030 (pursuant to the scoping memo, the ALJ's proposed decision will have issued in November, 2018). Thus, it no longer appears likely that the capacity available under the current Option R will be exhausted before the conclusion of SCE's GRC Phase 2 proceeding.

In comments on the proposed decision, CALSEIA/CALSSA take issue with the calculations in the PD, stating that they are inaccurate but not demonstrating why, or what the correct value should be. Our calculations above rely on more recent data from SCE's website (June 2018 vs. April 2018 in the PD) and CALSEIA/CALSSA have provided no reason to believe that data is inaccurate. Indeed, we note that this is the same website-derived data that serves as the basis for the calculations in Exhibit CALSEIA-100 that analyze progress toward the cap. If that data suited their purpose then, we are skeptical of CALSEIA/CALSSA's objection to the PD's use of the same data source when it undermines their arguments.

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[114] SCE's June 6, 2018 report is attached to this decision as Appendix 3.

[115] Exhibit CALSEIA-01 at 17, Q and A at lines 4-8.

CALSEIA/CALSSA also oppose the PD's reliance on the schedule adopted in the Scoping Memo for A.17-06-030, stating "…as is clear from this proceeding and many other rate cases, it is difficult for the Commission to issue decisions quickly."[116] We accord no weight to this gratuitous and disrespectful comment.

Finally, we address the argument in CALSEIA/CALSSA's comments on the PD that there are two sets of customers that would benefit if the cap is removed:

1. Customers committed to solar investments with expectations of completing installation before the cap is reached, but their projects have moved more slowly than anticipated and it is now highly uncertain whether they will be completed in time; and
2. Commercial customers considering investment in smaller systems that can be installed quickly could move forward if the cap is removed, particularly if some initial engineering has already been completed.[117]

Here, we direct CALSEIA/CALSSA back to the Scoping Memo in this proceeding, and the explanation there as to why the matter of the Option R cap would be considered in this proceeding: "CALSEIA presents a convincing argument that (1) the cap will be reached sooner than it can be addressed in SCE's 2018 GRC Phase 2, and (2) reaching that cap will present real-world difficulties to SCE customers who are interested in taking service under Option R rates."[118] Given the opportunity to make its case for lifting the cap, CALSEIA submitted testimony that did not, in fact, accurately estimate when the cap would be reached. Now, even though the cap has not been reached, and appears unlikely to be reached before the Option R tariff is replaced, CALSEIA/CALSSA argues that (1) "having a tariff cap for commercial customers that is based on the date of

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116 CALSSA Comments on the PD at 2.

117 *Id.* at 3

118 March 21, 2017 "Scoping Memo and Ruling of Assigned Commissioner" at 7.

interconnection approval is bad policy"[119] and (2) "commercial customers considering investment in smaller systems that can be installed quickly could move forward if the cap is removed."[120] CALSEIA/CALSSA's remedy for its first concern would have been an application for rehearing of either the Commission's first or second decisions regarding Option R: the Scoping Memo did not include this question in the scope of this proceeding. If CALSEIA/CALSSA's second assertion is accurate, since there is still room under the cap, those customers should complete their installations and begin to take service on an Option R tariff before the Commission issues a decision in A.17-06-030.

We also direct CALSEIA/CALSSA to the Commission's findings in D.17-10-018, its "Decision Granting Limited Modification and Otherwise Denying Petition for Modification of Decision 17-01-006." There, the Commission considered and denied a Petition for Modification filed by CALSEIA and SEIA that would expand eligibility for the grandfathering protection previously adopted in D.17-01-006. The Commission's explanation for its denial of the request is instructive here. First, the Commission noted that since it adopted D.17-01-006, it had received "extensive public comment from solar providers, public agencies, and others regarding the impact of the Decision on their business and on solar projects under consideration. In particular, public comment from the solar industry states that solar providers do not believe they can provide sufficient certainty to their customers to move ahead with solar projects."[121] We quote our response to CALSEIA and SEIA in some detail below in order to make clear that

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[119] June 11, 2018 CALSSA Comments on the proposed decision at 3.

[120] *Ibid.*

[121] D.17-10-018 at 4.

this Commission has already considered and rejected the arguments made by CALSEIA/CALSSA in their comments on the PD:

> In [D.17-01-006], we acknowledged that changes to TOU periods made in recent and near-term rate cases will be significant. Although changes to TOU periods are handled in individual IOU rate cases, the general parameters of the current dramatic shift are already known. Even where final TOU periods have not yet been approved by the Commission, the proposed new TOU periods, and the data to support those proposals is available.
>
> Solar providers have certainty that in the near future TOU peak periods will be set later in the day than previous TOU peak periods. Solar providers also have information, but not absolute certainty, regarding what new TOU time periods are likely to be adopted. <u>No customer has absolute certainty about future rate structures. Solar providers and their customers are not entitled to preferential treatment to the detriment of other ratepayers</u>.
>
> <u>It is the responsibility of solar providers to develop a business model that will provide sufficient certainty to their customers</u>. Solar providers, like any other business, will face some uncertainty. We are unpersuaded by the Petitioners' statement that, "There is no way for solar providers to 'handicap' for customers the odds of one [TOU rate] proposal being adopted over another." Solar providers can and should provide prospective customers different TOU and rate scenarios in order for customers to make an informed investment decision amidst some uncertainty. Solar providers can address risk by shifting it to their customers or by finding other mechanisms to address it, such as transaction structures that put the risk on the solar provider instead of the customer, or through a risk sharing mechanism.[122]

Finally, as noted in the PD we also wish to avoid creating a situation where, by lifting the cap, an inordinate number of new customers (*i.e.*, at a rate above historical trends) sign up for Option R before the end of the

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[122] D.17-10-018 at 8-9, citing the CALSSA/SEIA Petition at 7. Emphasis added.

year. SCE's witness discussed this "gold rush" phenomenon during hearings when explaining his disagreements with CALSEIA's calculations regarding when the cap might be reached:

> Mr. Thomas: Well, let me qualify the data. I just received it this morning. I was able to do a very quick review. I can say that the data looks at a very short period, so, therefore, the regression is essentially looking at the tip, or the end of regression, which would accelerate what you would see.
>
> What's included in this data, right, is the gold rush, or the rush of applications that preceded the TOU OIR final decision [i.e., D.17-01-006]. So, therefore, that would steepen the slope.[123]

We face a similar situation here, now that SCE has proposed a replacement for Option R in A.17-06-030: at the conclusion of R.15-12-012, once prospective customers could see what a prospective alternative to the current Option R might look like (*i.e.*, different TOU periods) they rushed to sign up for the current version. Here, prospective customers now know the specifics of SCE's proposed TOU periods, and they know that the Commission is considering a replacement for Option R in SCE's Phase 2 proceeding. We do not wish to encourage or create unlimited opportunities for new solar customers to take service on the current Option R while we consider its replacement in another proceeding before us.

Indeed, due to developments in the past year, CALSEIA's testimony has the unintended effect of reinforcing our conclusions. CALSEIA discusses the impact of uncertainty about Option R on non-residential solar projects:

> The average timeframe to complete solar projects is about one year, which means that projects that are starting development now [*i.e.*, late April, 2017] <u>would likely have to assume that Option R will not be available when the project comes online</u>. Thus, diligent solar developers are likely <u>already</u> informing

[123] RT at 16-17.

> potential customers that Option R might not be available when their systems become operational. This means that when customers perform their own due diligence, they would assume that Option R would not be available to them. Customers utilizing less solar friendly rates (*i.e.*, no Option R rates) in their analyses would yield less economically favorable results, making them far less likely to pursue these solar projects at all.[124]

Based on the above, if CALSEIA was correct that customers were already assuming in April 2017 "that Option R would not be available to them" then it is unclear why, over a year later, we would create more uncertainty, not less, if we changed the level of the Option R cap at this time. Regardless of whether the Commission ultimately approves SCE's newly proposed Option E, since we will soon be determining the future of Option R in A.17-06-030, we see little sense in raising the cap now. We prefer to take what we now see as a small risk that the 400 MW cap will be reached before the effective date of that decision.

17. SCE and SBUA Joint Motion for Adoption of Settlement Agreement

On August 7, 2017 SCE filed and served a "SCE-SBUA Joint Stipulation Resolving Issues in SCE 2016 RDW Proceeding", including what has since been admitted into evidence as Exhibit SCE-SBUA-1. Pursuant to Rule 12.1(b), on August 17, 2017 SCE provided notice to all other parties of its intent to conduct a settlement conference with respect to the joint stipulation between SCE and SBUA. On August 24, 2017 SCE and SBUA filed a Joint Motion for Adoption of Settlement Agreement regarding that stipulation.

[124] Exhibit CALSEIA-01 at 17-18, emphasis added.

17.1. The Settlement Agreement

The settlement agreement resolves all issues raised by SBUA in this proceeding, as follows:

> Article 2: Ensuring Small Business Customers Understand the New Rate Structure with Marketing, Education, and Outreach
>
> SCE agrees to submit high-level supplemental testimony in its pending GRC Phase 2 (A.16-06-030) by November 1, 2017, on expanded ME&O outreach to small business customers, with the following anticipated outline structure:
>
> Part I: Overview, Introduction and Background
>
> Part II: Customer Insights
>
> - Background Research
> - Barriers to Adopting TOU and CPP by Small Businesses
>
> Part III: Overall Marketing Plan
>
> - Marketing Objectives
> - Goals
> - Overarching Strategic Approach
> - Target Audiences
>   - o Small Commercial Customers
>   - o Other Customer Classes (Medium Business, Agriculture, Large Commercial and Industrial)
> - Messaging Strategy
> - Tactical Outreach and Education Plans
>   - o General Populations
>   - o Targeted I Impacted Populations
>
> Part IV: Measurement And Metrics (including awareness measurement and customer willingness to change behavior regarding TOU and CPP).
>
> Part V: Budget
>
> Article 3: Alternative Rate Structures for Small Businesses

SCE agrees to submit supplemental testimony in its pending GRC Phase 2 by November 1, 2017, outlining a planned study for exploring the possibility of an alternative rate structure specifically tied to GS-1 DG and Storage customers in light of the changing TOU periods.

Article 4: Additional Steps to Address the Impacts of SCE's New Rate Structures on Small Business Customers

4.1 Promoting Small Business Adoption of Clean Energy Measures

4.1.1 SCE will meet and confer with SBUA-designated representatives to discuss the possibility of commencing one or more potential studies to further explore promoting clean energy solutions within the context of new TOU periods.

4.2.1 The Settling Parties acknowledge that the Commission increased the total Self Generation Incentive Program ("SGIP") budget statewide to over $500 million through 2019. Small business customers are eligible to apply for SGIP program funding. SCE agrees to meet and confer with SBUA regarding the viability of SCE working with other program administrators to expand the eligibility of small commercial customers to apply for and receive small-scale energy incentives, as are provided to residential customers in 2016 SGIP Decision (D.16-05-055). Following this meet and confer session, SCE agrees in good faith to consider requesting in writing joint action with the other program administrators to expand or alter the SGIP to further incentivize small- scale energy incentives for small commercial customers.

17.2. Discussion

The Joint Motion is unopposed. We find that the Settlement Agreement meets the Commission's criteria for approval of settlement agreements pursuant to Rule 12.1(d) of the Commission's Rules of Practice and Procedure: it is reasonable in light of the whole record, consistent with law, and in the public interest.

18. Comments on Proposed Decision

The proposed decision of the assigned ALJ in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission’s Rules of Practice and

Procedure. Comments were filed on June 11, 2018 by SCE, ORA, CLECA, AECA and Farm Bureau (jointly), CALSSA, SEIA, and SBUA. Reply comments were filed on June 18, 2018 by SCE, CLECA and SEIA.

The majority of parties' comments focused on three issues: the PD's determination that October should remain in SCE's winter season; the PD's adoption of SCE's proposed winter season super off-peak TOU period; and the PD's determination that the Option R cap should be left undisturbed. Comments on those issues have been addressed in detail in the body of this decision. The PD has been modified extensively to provide clarifications, but the resolution of each issue in the PD has been left unchanged.

Other comments requested a number of more specific clarifications or changes to the PD. We address each of those requests here, and have made corresponding revisions in the body of this decision.

SCE requests clarification in the PD in four areas:

1. the implementation date for the proposals adopted therein;
2. eligibility for the indifference mechanism directed for RES-BCT customers impacted by the changing TOU periods;
3. the applicability of default CPP for customers with who have a currently-pending Direct Access (DA), Community Choice Aggregation (CCA), or Community Aggregation (CA) enrollment cut-over; and
4. formal adoption of the Settlement Agreement between SCE and the Small Business Utility Advocates (SBUA) entered into in this proceeding.

ORA requests a number of corrections to the PD:

1. The Commission should revise the PD to correctly reflect parties' positions on requiring default CPP to small commercial customers. The Commission should revise the PD to adopt SCE's proposal of optional CPP for small commercial customers as supported by the majority of intervening parties.
2. The Commission should revise the PD to correctly reflect ORA's recommendations for marginal costs, including marginal energy costs,

marginal generation capacity costs, and marginal distribution costs. Further, the Commission should revise language in the PD to clarify that the marginal cost values are only used for the purpose of developing TOU periods.

3. The Commission should revise the PD to correctly reflect ORA's recommendations on SCE's allocation of flexible ramping capacity costs.
4. The Commission should revise the PD to reflect ORA's regression validation of its proposed TOU periods.

CLECA requests revision of the PD to reference the statutory prohibition on cost-shifting in its discussion of RES-BCT.

AECA and Farm Bureau request revision of the PD to provide flexibility for implementation of the new TOU periods to allow simultaneous implementation with whatever new rates are adopted in SCE's GRC Phase 2 proceeding.

SEIA requests modification of the PD to clarify the relief afforded customers of the RES-BCT program.

SBUA requests modification of the PD to (1) explicitly adopt the SCE-SBUA Settlement Agreement; and (2) to determine that CPP for TOU-GS-1 customers should be an opt-in program, rather than require default enrollment.

18.1. Summary of Modifications in Response to Comments

First, regarding the implementation date of the TOU periods adopted in this decision, we have modified the PD to provide that the rates and tariff modifications approved in this decision should take effect no sooner than February 1, 2019 and shall be implemented simultaneously with any rate changes adopted in SCE's GRC Phase 2 proceeding.

Second, regarding the RES-BCT program, the PD directs SCE and the affected renewable energy water districts to work collaboratively in SCE's currently-open GRC Phase 2 proceeding to develop an indifference mechanism that will have the result that SCE's RES-BCT program continues to be a viable mechanism for the governmental entities that participate in the program. SCE requests revision of the PD to clarify that this mitigation measure applies only to existing RES-BCT customers (albeit, all existing customers, not just the customers represented by the REWDs that are parties in this proceeding). SEIA, on the other hand, requests revision of the PD to clarify that any indifference mechanisms formulated in A.17-06-030 and approved by the Commission would be available to all customers who are currently RES-BCT customers and those who apply to be RES-BCT customers in SCE's service territory until SCE's statutory RES-BCT MW cap is met. SEIA suggests that "this will help to ensure that the RES-BCT program is not effectively shut down prior to reaching the legislature's MW goals."[125] SEIA also recommends modifications to the PD to provide a timeline for the ordered collaboration, and an alternative procedural mechanism in the event mutual agreement is not reached. Finally, CLECA would clarify the PD by referencing text in the RES-BCT statute regarding cost-shifting.

SCE responded to SEIA and argues that SEIA's requested clarification that the indifference mechanism developed in A.17-06-030 should apply to future RES-BCT customers as well as current customers would contravene the intent of the TOU OIR decisions to apply mitigation measures to customers with existing systems or those in the process of installing systems.

We address these comments and replies as follows: first, we have not added the language suggested by CLECA, because the statute speaks for itself and will guide the Commission's actions in any event. Second, we respond to SCE and SEIA by first noting that the discussion of RES-BCT in the PD concludes by directing SCE and the Renewable Energy Water Districts to develop

> an indifference mechanism that, by mutual agreement, will have the result that the RES-BCT program continues to be a viable mechanism

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[125] SEIA Comments on the PD at 15.

> for the governmental entities that <u>entered</u> the program in good faith that it would not be effectively canceled <u>part-way through the life of the investments they made</u> to participate in California's efforts to reduce greenhouse gas emissions and help achieve the state's climate goals. (emphasis added)

In short, the solution adopted in the PD clearly applies only to who are currently RES-BCT customers, albeit to all such customers. However, SEIA makes a telling reference to "the legislature's MW goals" in its comments: Section 2830 (h) adopted a statewide cap on participation equal to 250 MW; SCE's proportionate share of that cap is based on the ratio of its peak demand to the total statewide peak demand of all electrical corporations. The PD found that "if we simply approve SCE's new TOU periods and take no further mitigating actions, we will have contravened the intent of the Legislature by effectively shutting down the program that we were directed to create when the Governor signed AB 2466" and noted that D.17-01-006 stated "although today's decision adopts grandfathering for a specific situation, we expect that going forward the IOUs, customers, and DER technology providers will develop mitigation measures that are more transparent and more narrowly tailored than grandfathering." Until SCE reaches its proportionate share of the RES-BCT cap, eligible entities can continue to enroll it its RES-BCT program, and this Commission remains obligated to ensure that SCE's program is attractive enough to those entities to produce steady progress toward SCE's cap. The PD could have included direction to this effect, but it did not. Instead, it adopted the narrow remedy we are discussing here. Therefore, we have simply revised the PD to leave that remedy in place, clarify its applicability, and direct further action in the future to address the overall viability of SCE's RES-BCT program.

Regarding CPP, SCE requests modification of the PD to clarify that to specify that customers with pending DA, CCA, or Community Aggregation program enrollments at the time of the implementation of this decision be exempt from defaulting to CPP to avoid customer confusion. SBUA recommends that the Commission make CPP an opt-in program for TOU-GS-1 customers. ORA asks that the PD be revised to correctly represent the positions of parties, and revised to afford small commercial customers optional CPP instead of default CPP. We have modified the PD as requested by SCE. ORA misunderstands the PD's statement that no party opposes SCE's alternative proposal, but we have modified that sentence to specifically reflect the positions of parties. However, we leave unchanged the PD's denial without prejudice of SCE's alternative proposal to offer CPP as an optional rather than a default rate to customers on its TOU-GS-1 and TOU-PA-3 rate schedules. The PD clearly states the proper procedural path for SCE, ORA or SBUA to follow in order to establish the evidentiary record necessary to support their proposals.

Regarding the settlement agreement between SCE and SBUA, we have modified to PD to make clear that the agreement is approved.

Finally, we have clarified the PD in areas requested by ORA, where warranted.

19. Assignment of Proceeding

Michael Picker is the assigned Commissioner and Stephen C. Roscow is the assigned ALJ in this proceeding.

Findings of Fact

1. Although not binding on this proceeding, D.17-01-006 describes the principles we should adhere to when considering whether to change the current TOU periods.

2. In D.17-01-006, the Commission defined "Base TOU periods" as those TOU time periods during which customers, generators, and providers of energy services should be encouraged to modify electric usage and supply.

3. In D.17-01-006, the Commission determined that Base TOU periods should be developed using utility-specific, forward-looking data, with the forecast year set at least three years after the Base TOU periods will go into effect.

4. Public Utilities Code Section 745(c)(3) directs the Commission to "strive" for residential TOU periods that are appropriate for at least the following five years.

5. SCE demonstrated that the differences in the results of its marginal cost studies for 2021 and 2024 with regard to determining TOU periods are not significant.

6. Absent a settlement, the Commission adopts values for marginal costs that are calculated using specific inputs.

7. SCE's proposed 2024 marginal energy costs are uncontested.

8. SCE's methodology for determining distribution marginal costs reasonably accounted for future DG penetration.

9. In D.17-01-006, the Commission determined that the use of marginal distribution and transmission cost information in setting future Base TOU periods will be addressed in individual IOU rate proceedings.

10. SCE's rebuttal testimony shows that summer weekday and weekend costs vary dramatically.

11. SCE's data supports retaining the current definition of SCE's summer season, June-September.

12. Evidence based on SCE's 2024 forecast and the resulting marginal cost estimates supports SCE's proposed TOU periods.

13. In D.17-01-006, the Commission specified that new TOU periods should be introduced in a manner that reduces or mitigates negative impacts on customers.

14. In D.17-01-006, the Commission established the qualifying attributes of customers with existing behind-the-meter solar who are entitled to remain on

existing TOU periods during a five or ten-year transition depending on the customer type.

15. In D.17-01-006, the Commission permitted the utilities to structure an alternative but equivalent mitigation measure for customers with existing behind-the-meter solar, subject to approval by the Commission.

16. The Renewable Energy Self-Service Bill Credit Transfer program (RES-BCT) program was established by the legislature effective January 1, 2009, and is codified in Section 2830 of the Public Utilities Code. Assembly Bill 512, signed into law in 2011 and effective on January 1, 2012, further modified the program to increase the generator size limit to 5 MW per generation account.

17. The RES-BCT program allows governmental entities, who may not have electric loads where the potential for renewable generation exists, to nevertheless install renewable energy generation projects in those locations.

18. The RES-BCT program credit for the exports to the grid is established using only the generation component of the TOU energy charge of the generator account rate schedule.

19. The Net Energy Metering tariff provides project owners a credit equal to the entire retail rate.

20. RES-BCT generation credits are heavily dependent on the peak hour pricing structure of SCE's TOU periods.

21. Evidence in this proceeding shows that the value of the solar energy produced by the renewable energy water districts' projects will decrease significantly once SCE's proposed TOU period changes take effect unless mitigating actions are taken beyond the grandfathering provisions established in D.17-01-006.

22. The Scoping Memo included the issue of whether the Commission should eliminate the cap on enrollment on SCE's Option R tariffs in the scope of this proceeding because good cause existed for doing so.

23. It no longer appears likely that the capacity available under the current Option R tariff will be materially exhausted before the conclusion of SCE's GRC Phase 2 proceeding.

24. The Settlement Agreement between SCE and SBUA is reasonable and its provisions offer benefits for small businesses.

Conclusions of Law

1. SCE's marginal cost study using reference year data from 2024 should be used in the marginal cost analyses for setting SCE's standard TOU periods.

2. SCE's uncontested 2024 marginal energy costs should be approved for use in this proceeding.

3. SCE's estimate of marginal generation capacity cost of $147.26 per kW-year should be approved for use in this proceeding.

4. SCE's proposed distribution marginal costs should be approved for use in this proceeding.

5. It is not necessary to incorporate marginal transmission costs into SCE's TOU period calculations at this time.

6. SCE's proposal to differentiate between weekdays and weekends for its summertime TOU periods should be adopted because it is supported by the underlying cost data.

7. SCE should retain its four-month summer (June-September) and eight-month winter (October-May) seasons.

8. SCE's proposed TOU periods should be adopted because they are supported by evidence in this proceeding.

9. The grandfathering proposals made by the Castaic Lake Water Agency, Rancho California Water District, and Renewable Energy Water Districts should not be adopted.

10. In D.17-01-006 the Commission adopted TOU rate period grandfathering for a specific situation but stated its expectation that going forward the IOUs, customers, and DER technology providers will develop mitigation measures that are more transparent and more narrowly tailored than grandfathering.

11. Pub. Util. Code Section 2830 (f) requires the Commission to approve a tariff, or specify conforming changes to be made, in order to implement the intent of the Legislature to allow local government entities to credit energy produced from renewable resources owned by the local entity against their electricity usage on more than just the facility where the renewable generator is located in a manner that creates a viable RES-BCT program.

12. SCE and the renewable energy water districts in this proceeding should collaborate in SCE's currently-open GRC Phase 2 proceeding (A.17-06-030) to develop an indifference mechanism that will have the result that the RES-BCT program continues to be a viable mechanism for the governmental entities that participate in the program.

13. The current 400 MW cap on Option R enrollment should not be increased or removed in this proceeding.

14. The Settlement Agreement between SCE and SBUA is reasonable in light of the whole record, consistent with law, and in the public interest.

15. The rates and tariff modifications approved in this decision should take effect no sooner than February 2019 and shall be implemented concurrently with any rate changes adopted in SCE's GRC Phase 2 proceeding.

ORDER

IT IS ORDERED that:

1. The time-of-use periods shown in Appendix 2 to this decision are adopted.
2. Southern California Edison (SCE) shall implement the specific terms of this decision as one or more Tier 1 Advice Letters concurrent with the filing of Advice Letter(s) to implement the proposals adopted in SCE's 2018 GRC Phase 2 Application 17-06-030.
3. Southern California Edison (SCE) and the affected renewable energy water districts, as defined in this decision, are directed to work collaboratively in SCE's currently-open General Rate Case Phase 2 proceeding (Application 17-06-030) to develop an indifference mechanism that, by mutual agreement, will have the result that SCE's Renewable Energy Self-Service Bill Credit Transfer program continues to be a viable mechanism for the governmental entities that currently participate in the program.
4. The August 24, 2017 Joint Motion of Southern California Edison Company and Small Business Utility Advocates for Adoption of Settlement Agreement is granted, and the Settlement Agreement attached to the Settlement Motion is approved.
5. Application 16-09-003 is closed.

This order is effective today.

Dated ____________________, 2018, at San Francisco, California.